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U.S. Nuclear Regulatory Commission

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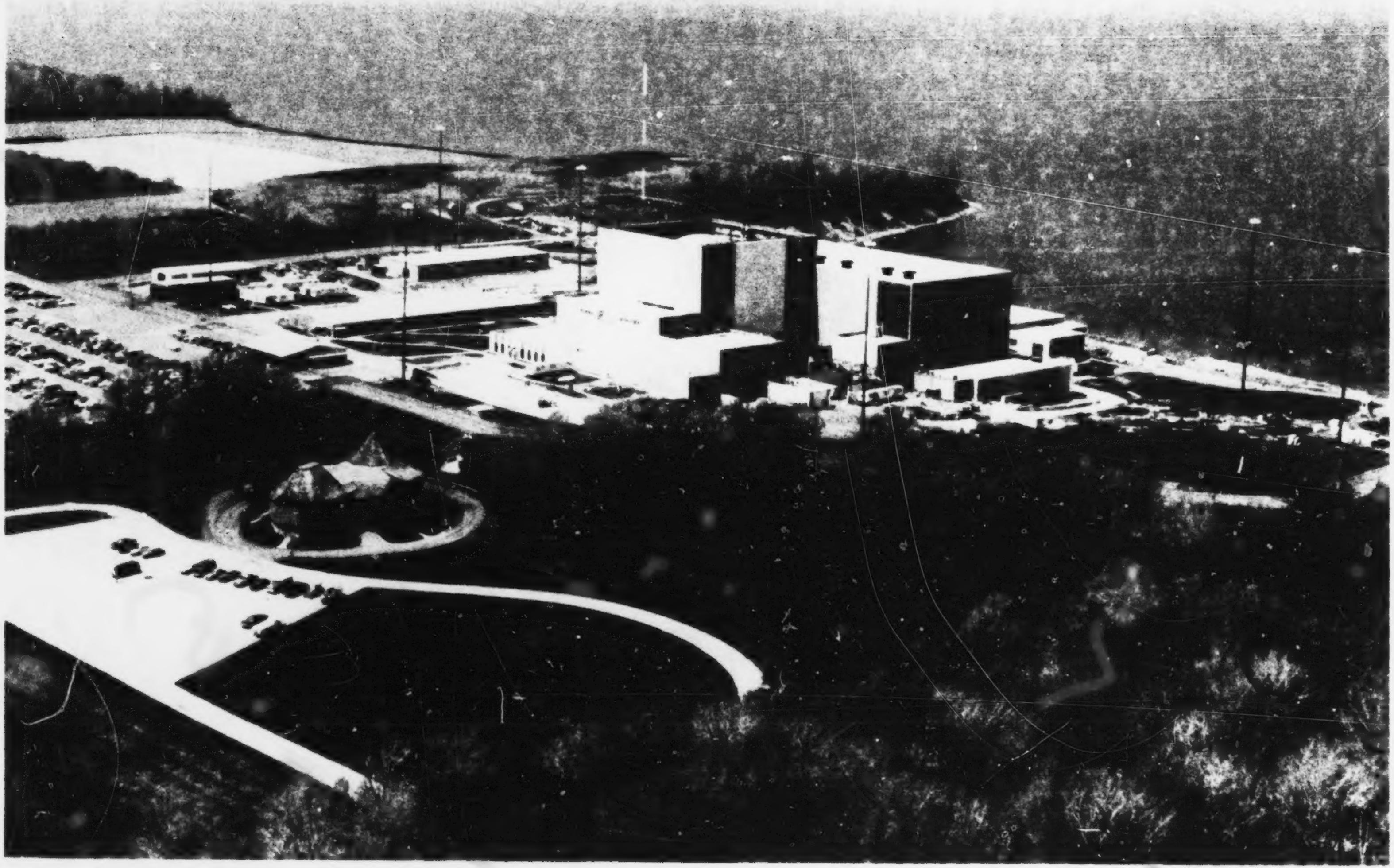

R. E. Ginna Nuclear Power Plant

ABSTRACT

This NRC Task Force report documents the circumstances surrounding the January 25, 1982, steam generator tube rupture event at the R. E. Ginna Nuclear Power Plant. It focuses on the period from 9:25 a.m. on January 25, when the tube rupture occurred, to 10:45 a.m. on January 26, when the plant entered the recovery phase. Information outside this period is recounted as necessary to place the event in perspective. The report is intended to describe the factual information and significant findings associated with the event and, thereby, provide the required data base for appropriate detailed analysis and recommendations by various NRC offices.

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AFW	Auxiliary Feedwater
ARAC	Atmospheric Release Advisory Capability
ARC	Alliance Research Center
ARMS	Aerial Radiological Measurements System
ASCO	American Switch Company
AVT	All-Volatile Treatment
B&W	Babcock and Wilcox
BAST	Boric Acid Storage Tank
BNL	Brookhaven National Laboratory
BRH	Bureau of Radiological Health
CDC	Center for Disease Control
CRDMS	Control Rod Drive Mechanism Shroud
CVCS	Chemical and Volume Control System
DE	Dose Equivalent
DFRP	Downcomer Flow Resistance Plate
DOC	Department of Commerce
DOD	Department of Defense
DOE	Department of Energy
DOT	Department of Transportation
DSO	Director of Site Operations
EBS	Emergency Broadcast System
EC	Eddy Current
EC	Emergency Coordinator
ECCS	Emergency Core Cooling System
ECTS	Electronic Custom Telephone System
EDRO	Office of Executive Director of Regional Operations
EERF	Eastern Environmental Radiation Facility
EICC	Emergency Information and Coordination Center
ETL	Environmental Team Leader
EMT	Emergency Management Team
ENS	Emergency Notification System

EO	Emergency Officer
EOC	Emergency Operations Center
EOF	Emergency Operations Facility
EPA	Environmental Protection Agency
EPIP	Emergency Plan Implementing Procedures
EPRI	Electric Power Research Institute
EST	Eastern Standard Time
ET	Executive Team
FAA	Federal Aviation Administration
FC	Flow Controller
FDA	Food and Drug Administration
FDA-EDRO	Food and Drug Administration's Office of Executive Director of Regional Operations
FEMA	Federal Emergency Management Agency
FSAR	Final Safety Analysis Report
FTS	Federal Telecommunications System
FW	Feedwater
GM	Geiger-Mueller (dosimeter)
GSA	General Services Administration
HHS	Department of Health and Human Services
HPN	Health Physics Network
HSIP	High-Pressure Safety Injection Pump
ID	Inside Diameter
IE	Office of Inspection and Enforcement
IGA	Intergranular Attack
IRC	Incident Response Center
ISI	In-Service Inspection
LCV	Level Control Valve
LH	Low Head
LOCA	Loss of Coolant Accident
LT	Level Transmitter
MOU	Memorandum of Understanding
MSIV	Main Steam Line Isolation Valve
MUT	Makeup Tank
NAWAS	National Warning System
NCS	National Communication System

NDE	Nondestructive Examination
NOAA	National Oceanic and Atmospheric Administration
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System
NWS	National Weather System
OD	Outside Diameter
ORNL	Oak Ridge National Laboratory
PAC	Public Affairs Coordinator
PCV	Pressurizer Control Valve
PHS	Public Health Services
PIC	Public Information Center
PIO	Public Information Officer
PORC	Plant Operations Review Committee
PORV	Power Operated Relief Valve
PRT	Pressurizer Relief Tank
PT	Pressure Transmitter
PWR	Pressurized Water Reactor
PZR	Pressurizer
RAT	Radiological Assistance Team
RCL	Reactor Coolant Loop
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCT	Response Coordination Team
RECS	Radiological Emergency Communications System
RES	Office of Nuclear Regulatory Research
RHR	Residual Heat Removal
RMWT	Reactor Makeup Water Tank
RPAM	Regional Public Affairs Manager
RSC	Reactor Safety Coordinator
RTD	Resistance Temperature Detectors
RV	Relief Valve
RWST	Refueling Water Storage Tank
SC	Site Contingency
SCC	Stress Corrosion Cracking
SEM	Scanning Electron Microscope

S/G	Steam Generator
SGTR	Steam Generator Tube Rupture
SIS	Safety Injection System
SJAE	Steam Jet-Air Ejector
SLO	State Liaison Officer
SLPS	State and Local Programs Support
SRI	Senior Resident Inspector
STL	Site Team Leader
SV	Safety Valve
TE	Temperature Element
TLD	Thermoluminescent Dosimeter
TMI	Three Mile Island
TSC	Technical Support Center
TSP	Tube Support Plate
USCG	U.S. Coast Guard
USDA	U.S. Department of Agriculture

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NRC REPORT ON THE JANUARY 25, 1982 STEAM GENERATOR TUBE RUPTURE AT R. E. GINNA NUCLEAR POWER PLANT

1 INTRODUCTION

1.1 Purpose

This report documents the circumstances surrounding the January 25, 1982, steam generator tube rupture event at the R. E. Ginna Nuclear Power Plant. It focuses on the period from 9:25 a.m. on January 25, when the tube rupture occurred, to 10:45 a.m. on January 26, when the plant entered the recovery phase. Information outside this period is recounted as necessary to place the event in perspective. The report is intended to describe factual information and significant findings associated with the event and, thereby, provide the required data base for appropriate detailed analysis and recommendations by various NRC offices. This latter effort and the resulting dissemination of information will ensure that NRC and the nuclear industry continue to profit from experience.

1.2 Background

This report is the product of an NRC Task Force composed of representatives of the Office of Nuclear Reactor Regulation, the Office of Inspection and Enforcement, the Office for Analysis and Evaluation of Operational Data, and the Regional Offices in Region I and Region III. The Task Force received valuable additional assistance from the Federal Emergency Management Agency, the NRC offices represented by Task Force members, and NRC contractors. The information documented in this report was developed through observations, testing, measurements, interviews, data analysis, audio-tape monitoring, video-tape enhancement, procedure walk-throughs, and document reviews. The licensee was not provided an opportunity to review or recommend changes to the report, but cooperated fully with the Task Force effort and provided raw data as requested.

1.3 Executive Summary

1.3.1 Facility Response

Prior to the tube rupture, the plant was operating at 100% power, with normal operating temperature and pressure. No indications of primary-to-secondary leakage existed. At 9:25 a.m. January 25, multiple control room alarms alerted the operators to a reactor coolant system (RCS) rapid depressurization. The air ejector radiation monitor alarm indicated to them the existence of a steam generator tube rupture; other alarms indicated the rupture was probably in the B steam generator. The operators commenced manual actions including a rapid turbine power reduction and an increase in the number and speed of the operating charging pumps. At 9:28 a.m., the continuing reactor coolant system pressure drop resulted in an automatic reactor trip and an automatic actuation of all three safety injection pumps. As a result of safety injection actuation, an automatic containment isolation occurred and the operating charging pumps automatically tripped. All safety systems operated as required. Both reactor coolant pumps were manually tripped and the operators then verified that natural circulation cooling had developed in both reactor coolant system loops. The pressurizer emptied and the reactor coolant system initial depressurization reached a minimum of about 1200 psig. The Task Force analysis of reactor coolant system pressure and reactor vessel upper head thermocouple temperature data indicated that a small steam formation probably developed under the reactor vessel upper head during the initial depressurization. If this bubble formed it would have subsequently collapsed as safety injection flow refilled the reactor coolant system.

Initially, operators cooled down the plant by dumping steam from both steam generators to the main condenser, while they confirmed the identity of the faulted steam generator. The B steam generator was isolated at about 9:40 a.m. and natural circulation in the B loop terminated shortly thereafter. Although all sources of feedwater to the B steam generator had been isolated, its water level continued to rise because of the flow through the tube rupture (break flow). At 9:55 a.m., the narrow-range water level indicator on the B steam generator went offscale high and subsequently the B main steam line started to fill.

At 9:57 a.m., the safety injection actuation circuitry was reset to allow resetting the containment isolation system. After containment isolation was reset, instrument air to the containment and, therefore, control of the air-operated valves inside containment, was restored.

At 10:07 a.m., operators attempted to equalize the pressure differential between the reactor coolant system and the B steam generator to stop the flow through the tube rupture by opening a pressurizer power-operated relief valve (PORV). This PORV was operated successfully three times. During its fourth operation the valve opened on command but, when the operator placed its controls in the closed position, the valve started to close, then reopened and remained in the open position. When the operator noticed that the PORV had failed, he manually closed its block valve to prevent the further loss of reactor coolant system inventory out of the open PORV. During these operations, the pressurizer level had risen rapidly, and the level instrument was now indicating offscale high.

Operation of the pressurizer PORV resulted in the formation of steam bubbles in the reactor vessel upper head region and in the top of the tubes in the B steam generator. The size of the bubble in the reactor vessel upper head region was estimated to be about 300 ft^3. The bubble in the steam generator tubes was smaller. The growth of these steam bubbles along with increased safety injection flow, had caused the rapid filling of the pressurizer. Natural circulation in the A loop and core cooling were not adversely affected by the existence of these bubbles.

One B steam generator Code safety valve lifted and closed three times as a result of pressurization of the B steam generator by the continued break flow; however, the safety valve may have leaked steam starting after the first lift. At 10:38 a.m., safety injection was terminated to prevent further safety valve lifts.

At 10:40 a.m., the condensate system was secured to prevent further radioactive contamination of the condensate storage tanks and the condensate demineralizers. The original contamination had resulted from the faulted B steam generator dumping steam to the condenser earlier in the event. To continue the plant cooldown, the operators relieved steam from the A steam generator to atmosphere using its PORV.

At about 10:42 a.m., pressurizer heaters were reenergized to assist in reestablishing a steam bubble in the pressurizer. They had automatically tripped as a result of low pressurizer level at about 9:28 a.m.

At about 10:52 a.m., the rupture disc on the pressurizer relief tank (PRT) burst as a result of inventory additions from three sources. A letdown line relief was the major contributor, with the pressurizer PORV and reactor coolant pump seal return line relief also adding water to the pressurizer relief tank.

At 11:07 a.m., one safety injection pump was started to provide a buffer for the anticipated drop in reactor coolant system pressure that the plant staff expected to occur as a result of the restart of the A reactor coolant pump. Again, at 11:19 a.m., a B steam generator safety valve lifted and closed; however, by this time the steam line had flooded sufficiently to cause water rather than steam to be released. At about 11:21 a.m., the A reactor coolant pump was started. The resulting coolant flow cooled and collapsed any remaining steam bubbles in the reactor vessel upper head region and the B steam generator. At about 11:37 a.m., a fifth lift of the B steam generator safety valve occurred and the safety injection pump was stopped. The safety valve closed but, apparently, continued to leak water at about 100 gpm.

At 11:52 a.m., the indicated pressurizer level returned onscale as a result of the continued break flow from the reactor coolant system into the B steam generator. Because pressurizer heaters had been reenergized earlier, a steam bubble was reestablished in the pressurizer. At 12:02 p.m., normal letdown from the reactor coolant system to the chemical and volume control system was reestablished. Because the B steam generator safety valve continued to leak, the tube rupture continued to drain the reactor coolant system to the B steam generator. The rate of decrease of pressurizer level, resulting from the continued flow through the break, prompted the operators to restart one safety injection pump. This was done at about 12:12 p.m. This pump was intermittently run to control pressurizer level until about 12:35 p.m. The B steam generator safety valve apparently stopped leaking at about 12:25 p.m., so the safety injection pump was not needed to control pressurizer level after this point.

At 12:27 p.m., the reactor coolant system and B steam generator pressures equalized. The operators then maintained indicated reactor coolant system pressure about 25 psi below B steam generator pressure to promote backflow through the tube break. At 6:40 p.m., the B steam generator water level returned onscale on the narrow-range indicator. The B steam generator was then cooled by a feed-and-bleed operation, with auxiliary feedwater being intermittently supplied to the B steam generator, while backflow through the break was allowed to continue.

At 7:00 a.m., January 26, the residual heat removal system was placed in operation. At 6:53 p.m., the licensee declared the plant to be in a cold shutdown condition.

The Task Force estimated the rate of flow through the ruptured tube using mathematical models and known plant system characteristics. By these estimates, the highest flowrate through the break occurred very near the onset of the rupture and was calculated to be about 760 gpm. A mass balance algorithm determined that about 117,000 lb of steam and water was released from the B steam generator.

The Task Force also reviewed the indicated temperature transient of the reactor coolant system loops in an attempt to determine whether the reactor vessel had experienced a significant thermal shock during the event. Using the plant parameter data available and the information known about the design of the plant, the Task Force modeled the thermal behavior of the reactor coolant system while the safety injection pumps were operating and the reactor coolant pumps were stopped. The results of calculations based on the model parallel closely the actual transient experienced. Although the model provides a plausible explanation of the transient and calculations based on the model indicate that a significant thermal shock did not occur, the possibility of a significant thermal shock to the reactor vessel wall during this event has not been ruled out.

1.3.2 Human Factors Considerations

The NRC Task Force conducted a human factors review of the Control Room and Technical Support Center designs, a review of personnel responses, and a review of the procedures as they supported the steam generator tube rupture event. The review also included a comparison of the procedures with the Westinghouse Owners' Group guidelines. These reviews were accomplished through interviews with plant personnel, examination of the Control Room, the Technical Support Center, the procedures as they compared with human factors guidelines, and partial walk-throughs of the event with operators.

The Control Room and Technical Support Center physical facilities were satisfactory to support the activities required to mitigate the consequences of this steam generator tube rupture event. In addition, the response of the licensee's plant staff to the event was good.

In general, based on the training and experience of the plant staff, the applicable procedures were adequate for coping with the event. Problems with the procedures are identified.

1.3.3 Radiological Consequences

The NRC Task Force estimated the curies available for release from the reactor coolant system, the amount of activity transferred to the faulted steam generator, and the activity released to the environment as a function of time. Both airborne and liquid releases were estimated. Airborne release figures were then converted to projected offsite dose figures using conservative dispersion models based on existing weather conditions.

On- and offsite radionuclide release and exposure measuring devices were read and results analyzed. Risk to the public and licensee personnel were then estimated.

Most of the radionuclides released from Ginna were released during the first 3 hours of the event. During this period the wind was blowing toward the southeast. Snow and the moist cold air caused a large fraction of the radioiodines and particulates released from Ginna to deposit on the Ginna site, rather than to remain airborne beyond the site boundary. The Task Force estimated that airborne releases to an owner-controlled, unrestricted area exceeded the limits in 10 CFR 20. Other offsite releases were estimated to be less than 25% of the limit for unrestricted areas. All releases would result in doses which were significantly less than the 10 CFR 100 guidelines.

Potential health impacts from the estimated doses and predicted exposures were insignificant compared with the natural incidence of cancer fatalities and genetic abnormalities.

1.3.4 Institutional Response

Various organizations, including the licensee, State and local governments, NRC, and other Federal agencies responded to the event at Ginna.

The licensee had primary responsibility for resolving the conditions that existed at the plant. Prescribed initial notifications by the licensee to the State, local counties, and NRC were completed very early in the event, and interactions throughout the event were maintained among all the participants.

The Nuclear Regulatory Commission, using the resources of the Senior Resident Inspector, the Region I Base and Site Teams, and the Headquarters Executive and Analytical Teams, monitored the licensee's actions in response to the event to assure that these actions were correct and appropriate.

The State of New York and Wayne and Monroe Counties were promptly notified by the licensee. They responded by activating their Emergency Operations Centers and sending representatives to the site. Monroe County also fielded offsite radiological monitoring teams and reported results back to the Emergency Operations Center throughout the day. Twice during the first day of the event, the Governor of New York was briefed by the NRC Chairman on the status of the event.

The Federal Emergency Management Agency (FEMA) was notified of the event by NRC. FEMA then coordinated the Federal agency nontechnical response, both from their Headquarters and from their Region II facility in New York City. Agencies contacted by FEMA were: the U.S. Department of Agriculture, the Department of Energy, the Coast Guard, the Department of Housing and Urban Development, the Department of Transportation, the National Oceanic and Atmospheric Administration, Environmental Protection Agency, General Services Administration, Department of Health and Human Services, and the Department of Defense. Each of the agencies notified was prepared to respond in accordance with the responsibilities defined in the National Radiological Emergency Prepared/Response Plan.

1.3.5 Post-Event Activities

After the plant was placed in cold shutdown, the licensee established conditions to support the identification of the ruptured tube in the affected steam generator. On January 31, the plant staff completed purging hydrogen and other noncondensible gases which had accumulated in the B steam generator as a result of the reactor coolant system inleakage, to the waste gas system. On February 1, the plant staff completed a reactor coolant system and B steam generator drain-down procedure. Aside from a reactor coolant system deboration event that occurred during a subsequent steam generator flush operation on February 3 and 4, no major problems were encountered by the plant staff.

The licensee determined that the ruptured tube was located at row 42, column 55 (R42C55) on the hot-leg side of the steam generator by a hydrostatic test. Nondestructive examinations of this tube, including eddy-current, radial profilometry, fiber optics, and visual inspections, determined that the rupture was about 4 in. long and 0.7 in. wide at its center. The rupture was centered at about 5 in. above the tubesheet. The rupture was fish-mouth-shaped and was later determined to be pointing outward along tube column 55. The tube appeared ballooned at the rupture location and had a wall thickness at the center of the rupture of less than 5% of nominal thickness. Markings on the exterior of the tube had the appearance of fretting wear.

TV-optics examination inside the B steam generator identified damage to additional tubes that had been previously plugged because of eddy-current indications, previous leakage, or their proximity to other plugged tubes. In addition, foreign objects and tube fragments were also found in the B steam generator. An examination of the A steam generator also revealed the existence of some small foreign objects.

Neither the licensee nor the NRC had conclusively determined the cause of the tube rupture at the time this report was prepared, but both organizations continue to study the matter.

1.4 Significant Findings

1.4.1 Facility Response

1. The steam generator tube failed suddenly and without any prior indication of a leaking tube.

2. The initial reactor coolant system depressurization, caused by the break flow, probably resulted in some steam formation in the region under the relatively hot reactor vessel upper head. This steam bubble would have condensed during the subsequent period of natural circulation and safety injection operation.

3. All engineered safeguard features operated as designed.

4. After the reactor coolant pumps were tripped, natural circulation flow developed in both reactor coolant system loops. Natural circulation flow ceased in the faulted steam generator loop after the steam generator was isolated and equilibrium conditions developed.

5. The reactor coolant system depressurization, resulting from manual operation of one pressurizer PORV, resulted in steam formation in the relatively hot and stagnant areas of reactor vessel upper head region and the primary side of the top of the tube bundle of the faulted steam generator. The pressurizer PORV was being used as required by procedure to reduce the reactor coolant system-to-faulted steam generator differential pressure, which controlled break flow rate. The pressurizer spray was not utilized, because the reactor coolant pumps, which provide normal spray pressure, had been stopped, as required by procedure, and the differential temperature between the pressurizer and the auxiliary spray source exceeded technical specification limits. The resulting steam formations and increased safety injection flow rates during the system depressurization caused the pressurizer level to go offscale high. Very little, if any, liquid was relieved by the pressurizer PORV before its block valve fully closed.

6. One pressurizer PORV stuck open after three successful cycles and the corresponding block valve had to be shut. The relief valve stuck open as a result of a malfunction of its pneumatic control system. The exhaust piping from the PORV's pneumatic control solenoid valve had been crimped by the licensee to reduce the PORV closure speed. The solenoid valve manufacturer's literature states that restricting the exhaust port may cause malfunctions.

   An exhaust piping restriction greater than that provided by the crimp is required to duplicate the observed relief valve motion. The cause of the increased restriction, which disappeared two days later, has not been identified.

7. The main steam system valve position recorders failed to indicate openings of the faulted steam generator safety valve and both A and B steam generator atmospheric PORVs. The latter failure resulted from slide contacts that were mispositioned. The cause of the failure of the safety valve openings to be indicated on the recorder is unknown.

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8. Based on Task Force analysis of available data from the instrumentation installed at Ginna, significant thermal shock of the reactor pressure vessel wall has not been ruled out. Significant thermal shock to the reactor pressure vessel wall could occur as a result of its exposure to the approximately 90°F water from the safety injection system after the reactor coolant pumps were tripped. During this event, the indicated temperature transient in the reactor coolant system cold-leg loop piping attached to the intact steam generator and the calculated magnitude of natural circulation flow precludes significant thermal shock to the reactor pressure vessel from safety injection flow into that loop. However, the indicated temperature transient in the cold-leg loop piping attached to the faulted steam generator does not by itself preclude the possibility of significant thermal shock from safety injection to this loop. The Task Force was able to closely approximate the indicated temperature transient of the faulted steam generator loop with a model which assumed flow toward the break location. The results of this model suggested that safety injection flow to the faulted loop may not have caused significant thermal shock to the reactor vessel.

   The reactor vessel did experience a cooling transient on the order of 100°F/hr during the first hour of the event as a result of the plant trip and subsequent cooldown.

9. Two hours after the start of the event, a reactor coolant pump was restarted in the nonfaulted reactor coolant system loop, which equalized temperatures in the loops and reactor vessel, collapsed any remaining steam bubble in the reactor vessel upper head and faulted steam generator tube bundle areas, and assisted in stabilizing and cooling the reactor coolant system.

10. The pressurizer relief tank rupture disc burst as a result of the tank being flooded. The significant contributors to the tank water inventory during the event, in the order of their significance, were the letdown orifice downstream line relief valve, the reactor coolant pump seal injection return line relief valve, and the one pressurizer PORV used for depressurization. The letdown line relief valve lifted when the pressurizer level indication returned from offscale low, while the letdown

containment isolation valve remained shut. The seal return line pressurized and the relief lifted after containment isolation.

11. The lowest setpoint ASME Code safety valve on the faulted steam generator opened five times during the event. The openings were the result of break flow pressurizing the steam line due to prolonged operation with reactor coolant system pressure greater than that in the B steam generator. The reactor coolant system pressure was greater because of the operation of charging and safety injection pumps. The faulted steam generator was overfilled by the flow through the break and the main steam line flooded with water. The Code safety valve was found to open and close at sequentially decreasing pressures. A water inventory balance and the observed safety valve opening characteristics indicate water and two-phase flow were relieved through the valve during the last two openings. The safety valve may have leaked steam after its first opening and apparently leaked water at a rate of about 100 gpm for approximately 50 min after its last opening.

    The B main steam line hangers outside the containment were pinned during the event after the line was flooded, as directed by licensee management who were concerned with the dead weight water load in the steam lines and the potential for water hammer phenomenon during depressurization. Cooldown of the reactor coolant system did not directly affect the temperature of the trapped hot water in the steam line.

12. Operators are expected to use the best means available to them to safely cope with an event, regardless of the safety classification of the equipment utilized. During recovery from this steam generator tube rupture event, operators used a variety of equipment classified as non-safety-related which, in general, functioned without problems. In most instances, non-safety-related equipment was backed up by safety-related equipment that could provide the same function or effect, if the non-safety-related equipment was unavailable. During this event, operators relied upon three sets of non-safety-related instruments which did not have safety-related backup during certain periods of the event; i.e., reactor core exit

thermocouples during the period reactor coolant pumps were tripped and natural circulation had not been verified; the reactor vessel upper head region thermocouples during the period reactor coolant pumps were tripped; and reactor coolant loop wide-range pressure instrumentation during the period following initial depressurization below 1700 psig. These instruments were used to track the course of the event and to verify adequate core cooling. After the initial depressurization, the wide-range loop pressure instrument provided the only direct indication of reactor coolant system pressure in the control room, other than the non-safety-related computer, for the range of pressures experienced during the event. The process computer failed for 16 min during the event and the cause of the failure is unknown.

13. Accurate analyses of the reactor coolant system water inventory, safety injection and charging flows, tube rupture flows, and safety valve releases could not be made with the permanent records generated at Ginna. Tank levels for the refueling water storage tank, boric acid storage tank, makeup tank, holdup tank, and volume control tank were not trended or automatically recorded. Safety injection and charging flows were indicated but not continuously recorded. The computer did provide information on charging flow when requested, but when more than one charging pump was operating, the actual flow rate was unknown because the range of the flow instrumentation was approximately one-third of the maximum charging flow capability. Trend data provided by the computer was of analytical value in establishing approximate times and effects of significant events.

1.4.2 Human Factors Considerations

1. In general, the actions of the operators and licensee management demonstrated that they understood their plant and the procedures and philosophy for coping safely with steam generator tube rupture events. They paid particular attention to the need for ensuring adequate core cooling and carefully assessed anomolous information to determine a prudent course of action when basic assumptions of procedures being used were not met.

2. Given the level of training and knowledge demonstrated by the involved operators, and their philosophy that no procedure should be followed blindly, the combination of procedures utilized during the event did assist operators in making decisions that were technically adequate to safely cope with the event. Procedural problems were identified during the event which caused the operators to make considered deviations from the procedures, resulting in delays in operator actions that were intended to mitigate releases to the environment.

3. Operators quickly determined that the plant had experienced a major steam generator tube rupture (SGTR) event based on the reactor coolant system response to the break flow and the coincidence of the air-ejector exhaust radiation monitor alarm. Operators suspected that the B steam generator had experienced the failure upon receipt of the B steam generator level deviation and steam flow/feed flow mismatch alarms - symptoms not discussed in the emergency procedure. Operators confirmed that the fault was in B steam generator by performing a radiation survey of the main steam line; an action not directed by procedure. The faulted steam generator was isolated within about 15 min after the time of rupture.

4. Operators tripped the reactor coolant pumps as required by the steam generator tube rupture procedure, when reactor coolant system pressure had decreased to about 1715 psig, following the initiation of safety injection. The licensee's basis for specifying the criteria for tripping the reactor coolant pumps at $\leqq$ 1715 psig, rather than the lower pressure recommended by the plant vendor, was that it was close to the lowest pressure that could be indicated on an environmentally qualified instrument.

5. The licensee's steam generator tube rupture procedure, when followed literally, will usually result in the formation of steam in the reactor vessel upper head area for conditions of large break flows. With the reactor coolant pumps tripped, the cooling rate in the reactor vessel head area is retarded because of low flow conditions in this area. Subsequent reactor coolant system depressurization using the pressurizer PORV to limit the break flow would then usually result in steam formation beneath

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the reactor vessel upper head. The procedure did not provide information to assist the operator in identifying the formation of a reactor vessel upper head steam bubble or instruct them in the techniques to monitor and safely handle the steam bubble. The procedure did not direct the operator to procedures designed to handle the situation.

A procedure entitled "Void Formation In The Reactor Coolant System" did exist and was used; but literally, the procedure did not apply, since it did not address void formations which occur at core exit temperatures of less than 700°F.

Despite these problems, the operators recognized the steam bubble formation and monitored its existence and effect on core cooling using reactor vessel upper head and core exit thermocouples. The operators did not terminate safety injection, even though they had literally met the termination criteria, until they were confident that termination was the prudent action.

6. The licensee's steam generator tube rupture procedure did not include a safety injection termination criterion which addressed the assurance of adequate core subcooling; however, the operators constantly monitored the saturation monitors and further verified core subcooling by use of the computer and by manual calculations.

7. Neither the licensee's steam generator tube rupture procedure nor the revision of the Westinghouse guidelines on which it was based contained instructions for coping with a failed open or leaking atmospheric PORV or Code safety valve on the faulted steam generator steam system.

8. During plant conditions of a pressurizer PORV stuck open, both pressurizer relief block valves shut, a steam bubble in the reactor vessel upper head region, a liquid-filled pressurizer and a faulted steam generator Code safety valve periodically relieving reactor coolant to the environment, the operators recognized the need to cooldown the reactor vessel head, collapse the steam bubble and then depressurize the reactor coolant

system to limit the radioactive material releases to the environment. The operators felt constrained to sequentially follow the steps of the steam generator tube rupture procedure regarding termination of safety injection and reestablishing normal pressurizer pressure control before restarting a reactor coolant pump. Not withstanding this view, the operators and licensee management assessed the situation, determined an appropriate course of action outside procedural guidelines, monitored the reactor vessel steam bubble with reactor vessel thermocouples, compressed the bubble with charging and safety injection pumps and restarted a reactor coolant pump.

9. The licensee cooled the faulted steam generator by alternately feeding it with cold auxiliary feedwater and then letting it flow through the break to the reactor coolant system, which was then at a slightly lower pressure. The licensee closely monitored the reactor coolant system for signs of excessive boric acid dilution and completed the steam generator cooldown with six to eight feed-and-bleed cycles.

10. The PORV for the B steam generator was isolated early in the event. Isolation of the PORV resulted in challenging the lowest setpoint steam generator Code safety valve with a two-phase flow condition for which it was not qualified. Had a safety valve stuck open or failed to seat tightly after a lift, as one apparently did, isolation of the leakage path using a block valve was not an available alternative as it would have been with the PORV performing the relieving function.

11. At Ginna, the automatic switchover of the safety injection pump suction from the boric acid storage tanks to the refueling water storage tank, on low level, occurs only if the safety injection signal is not reset. The licensee's steam generator tube rupture procedural requirements would prevent the operators from resetting safety injection signals until the automatic switchover had taken place. Manual switchover is not addressed in the procedure. Manual switchover or automatic switchover logic that is independent of safety injection reset would have allowed the operator to reset safety injection approximately 2 min into the event. Reset of

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safety injection would permit reset of containment isolation, which would further permit the operators to reestablish instrument air to the containment for operation of air-operated valves. These valves included: reactor coolant system letdown, normal pressurizer spray, auxiliary pressurizer spray, reactor coolant pump No. 1 seal return, pressurizer PORV, normal charging, and auxiliary charging. Reset of containment isolation would permit establishing normal seal water supply and return for the reactor coolant pumps. The limitations imposed by the switchover logic circuitry and procedures delay utilization of equipment which can mitigate the consequences of a steam generator tube rupture.

12. Rupture of the pressurizer relief tank rupture disc was avoidable by placing the control switch for the letdown orifice valve (200B) in the closed position when the valve closed on loss of instrument air, or by shutting the letdown orifice valve (200B) when the following pressurizer relief tank indications and alarms were presented in the control room:

    - high pressure alarm at 10:09 a.m.
    - high temperature alarm at 10:10 a.m.
    - high level alarm at 10:26 a.m.
    - pressure 50.5 psig at 10:31 a.m.
    - level 90% at 10:45 a.m.

13. The reactor coolant loop subcooling meter design was such that the indicated subcooling value was correct when T_{HOT} was above 500°F. When T_{HOT} was below 500°F, the meter indicated half the actual value. The only display of T_{HOT} was on the computer. This condition required the operator to remember to check T_{HOT}, and then perform a mental conversion on the displayed subcooling value.

    Reactor coolant subcooling indication was also available on request from the computer, based on an average of a set of core exit thermocouples and pressurizer pressure.

14. The pressurizer PORV and block valve switches were located side by side and appeared to be identical. However, the PORV switch was a three-position latching type; the block valve switch was a momentary-contact, spring loaded-to-center type. There was no obvious way to identify the difference in switch operation or whether the spring-loaded switch had to be held until the motor-operated valve closed or opened fully. These limitations had no effect on the cause of the event.

15. The 6-ft separation between the reactor coolant system wide-range pressure recorder and the pressurizer PORV controls required the control room operator to rely on someone else to describe the results of opening the PORV. The task was forced into a two-person, multiple, bump-and-wait type of operation. The PORV stuck in the open position after the fourth operation.

16. A survey of the control room consoles by members of the NRC Task Force, several weeks after the event, disclosed that numerous indicator lights were burned out, precluding an expeditious determination of equipment status.

17. There were several examples of inconsistent use of terminology on the control panels and between the panels and the plant procedures.

1.4.3 Radiological Consequences

1. It was estimated that a total of about 90 curies of noble gases were released, mostly from the steam jet-air ejector. About 0.4 curies of dose-equivalent I-131 (a total of about 5 curies of all isotopes of iodine), and about 1.3 curies of cobalt, molybdenum, barium, and cesium were estimated to be released, mostly from openings of the faulted steam generator Code safety valve. About 25 curies of tritium may have been released, some from the air ejector and trace amounts from the safety valve openings.

The estimated figure for noble gases released is believed to be conservative, due to the large volume of highly radioactive gases discovered in the faulted steam generator after the event. Unfortunately, these gases were removed from the generator before their curie content was accurately determined.

2. During this event, the estimated releases of iodine did not exceed those calculated for the design-basis steam generator tube rupture, since the design-basis analysis assumes an iodine-spiking factor (apparently not present during the event) and a reactor coolant iodine activity concentration equal to Technical Specification limits. Actual reactor coolant iodine activity concentration prior to the event was approximately 2% of the Technical Specification limit. However, the Task Force estimates of the proportions of available iodine and particulate radionuclides released, relative to the initial concentration of these radionuclides in the reactor coolant system, exceed that ratio assumed in the design basis steam generator tube rupture analysis. During the event, a faulted steam generator Code safety valve relieved water in the liquid phase as a result of the break flow flooding the main steam line. The release of liquid, rather than the steam release assumed in the design-basis analysis, results in a release of a larger proportion of the available iodine in the faulted steam generator, because during a liquid release there is no partitioning of iodine between the liquid and vapor phases. The design-basis analysis assumption that only steam releases occur favors the retention of iodine in the steam generator water due to partitioning.

   Finally, the releases of nonvolatile cobalt, cesium, barium and molybdenum nuclides during the event exceed those assumed in the design-basis analysis, since the design-basis analysis assumes steam releases which would not contain these radionuclides.

3. Comparison of air sample results from the licensee's fixed air-sampling stations and portable air-sampling devices, with the limits for airborne radionuclide concentrations specified in 10 CFR 20, indicated that during the event airborne concentrations in unrestricted areas offsite were less

than 25% of those permissible in unrestricted areas for continuous exposure over a full year. Airborne concentrations in the unrestricted area near the Brookwood Training Center (onsite) exceeded 10 CFR 20 limits for average yearly airborne concentrations. All releases would have resulted in doses far less than 10 CFR 100 guidelines.

4. Results of tap water samples taken by the licensee, onsite and at the Ontario Water Works, indicated no radionuclide concentrations above minimum detection capability of the instruments and procedures used.

5. Because of the wide variability in area, depth, and thickness of the snow samples collected, measured concentrations of radioactive materials in snow could not be used to determine deposition quantitatively. However, a comparison of the relative concentrations for snow collected onsite and offsite demonstrated that a major portion of the radioactive materials was deposited within the site boundary.

6. With one exception, environmental surveys did not show radiation levels above background levels beyond the plant boundary. The exception was a single measurement taken about 11:00 a.m. on January 25 at the intersection of Lake and Ontario Center Roads, which indicated an exposure of 1.2 mrad. Additional surveys early in the afternoon indicated that this area had returned to background. In addition, portable instrument surveys made by Wayne County personnel did not indicate radiation levels above background.

7. Offsite thermoluminescent dosimeter (TLD) readings by NRC and the licensee indicated that dose levels during the event were about the same as expected from background radiation sources. With the exception of two TLD onsite that were located approximately 0.2 mile downwind (SE) of the release point, no TLD measurement indicated a dose significantly above background. The two TLDs recorded doses of 21.7 ± 2.7 mrem and 9.4 ± 0.19 mrem and were located at the approximate centerline of the predicted plume. Most of this TLD exposure probably came from radioactive materials deposited on the ground and nearby surfaces rather than from the plume itself.

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8. The dose to the whole body of the maximally exposed individual onsite is unlikely to have exceeded about 15 mrem. The highest dose to any organ (e.g., the thyroid of an adult) of the maximally exposed individual onsite was unlikely to have exceeded about 40 mrem.

9. The dose to the whole body of the maximally exposed individual offsite is unlikely to have exceeded about 0.5 mrem. The highest dose to any organ of the maximally exposed individual offsite is unlikely to have exceeded about 5 mrem.

10. For the population within a 50-mile radius of Ginna, the total body population dose commitment from all pathways was estimated to be less than 0.1 person-rem.

11. The estimated dose to the total body of the maximally exposed individuals onsite and offsite, from radionuclides released during the event are small fractions of the average annual dose from exposure to natural background radiation in the United States.

12. The total collective dose accumulated by the 146 licensee employees involved in the event on January 25 was 644 person-mrem. The maximum whole-body exposure recorded for an individual exposed during the event was 240 millirems.

13. The risk from exposure to radioactive materials released from Ginna is low compared with many other types of risk (radiation-related or otherwise), and the radiation-related risks are based on conservative assumptions; therefore, the risk to real individuals from exposure to radioactive materials released from Ginna was insignificant.

14. Comparing the risk from exposure to radioactive materials released from Ginna with the risk from the normal incidence of cancer fatalities and genetic abnormalities in the general population, the risk to the public health and safety from this exposure is insignificant.

15. The risks to the work-force at Ginna are very small fractions of the estimated normal incidence of cancer fatalities and genetic abnormalities.

1.4.4 Institutional Response

1. The categories in which the event was classified were consistent with those in the licensee's Emergency Plan. The licensee's Emergency Plan Implementing Procedures did not provide detailed criteria to be used for an orderly deescalation of emergency classifications. During plant recovery, criteria for deescalation were developed according to existing conditions by licensee management with the concurrence of the NRC Director of Site Operations.

2. The licensee had no alternative evacuation site available for plant personnel during this event, nor does NRC require one. The designated evacuation site was in the path of the release plume; thus, some evacuated workers were contaminated.

3. State and county officials jointly decided not to use the prompt notification system during this event.

4. Although the licensee provided adequate notification that a steam bubble had formed in the reactor vessel head, this information was not relayed promptly by State personnel to their supervisors.

5. The NRC Senior Resident Inspector functioned effectively throughout the event, particularly during the period he was the sole NRC presence at the site.

6. The results of assessments of the event by Region I Base and NRC Headquarters teams were not directly coordinated and the communications between the Resident and Region I Base teams were not always tied into the NRC Operations Center.

[redacted]

7. The Health Physics Network, Federal Telecommunications System, and commercial telecommunications systems functioned adequately, whereas the Emergency Notification System (ENS) link was only marginally acceptable. Some problems encountered were attributable to background noise in the room where the phones were located (e.g., Region I's Incident Response Center), while other problems arose from the phone's location relative to essential sources of information (e.g., the Emergency Notification System phone in the Ginna control room). The Emergency Notification System lines also experienced continuous midband frequency noise, intermittent high-pitched tones, and unexplained breaks.

8. The staff of the NRC Headquarters Operations Center failed to make some notifications in a timely manner, as was required.

1.4.5 Post-Event Activities

1. The licensee's procedure for analyses of the hydrogen and total gaseous activity of the noncondensible gases trapped in the top of the faulted steam generator was in error. This problem caused a loss of post-event information but had no impact on the public health and safety, since the gases were later processed and monitored before release in the licensee's waste gas system.

2. The licensee's procedure for flushing the faulted steam generator to remove dilute boric acid caused a minor deboration of the reactor coolant system. The boric acid concentration in the reactor coolant system, however, remained far in excess to that required for an adequate core shutdown margin.

3. A number of foreign objects were found in and removed from the secondary side of the faulted steam generator. The largest object had the same appearance and metallic characteristics as part of the steam generator downcomer flow resistance orifice plate. This plate had been cut in pieces and reportedly removed during a steam generator modification in 1975. In addition, some previously plugged tubes displayed evidence of

gross mechanical damage, and at least two of these tubes were fractured and found skewed between the tube bundle and the steam generator shell. Some small foreign objects were also found in the A steam generator.

4. The ruptured tube had a fish mouth opening 4.1 in. long and 0.7 in. wide at its maximum point, centered approximately 5 in. above the tube sheet, with the opening oriented along its tube column toward the steam generator shell. The tube appeared ballooned at the rupture location and had a wall thickness at the center of the rupture of less than 5% of nominal thickness. Markings on the exterior of the tube had the appearance of fretting wear.

[redacted]

2 GINNA EVENT CHRONOLOGY*

Time and Event	Section Reference	Comment
January 25, 1982		
9:22 a.m.		
Initial conditions: plant power, 100%; indicated reactor coolant system (RCS) loop pressure, 2197 psig; indicated RCS loop average temperature, 572°F; indicated pressurizer pressure, 2235 psig; other primary and secondary parameters normal; primary-to-secondary leak rate, 0 gpm.	3.2.1 and 4.2.1	The primary-to-secondary leak rate was last calculated based on air ejector monitor indications on January 7, 1982. Air ejector radiation monitor indications had been essentially constant since January 24, 1982. No known plant operations that would have caused or affected the event were in progress.
9:25 a.m.		
The following alarms were received in the control room: charging pump speed alarm; B steam generator level deviation alarm; B steam generator steam-flow/feed-flow mismatch alarm; pressurizer level and pressure deviation alarms; air ejector radiation monitor (R-15) alarm; pressurizer low pressure alarm (setpoint, 2185 psig).	3.2.2 and 4.2.1	First indications of the tube rupture in B steam generator. One charging pump, which was in automatic pressurizer level control, was now at its maximum speed. The speed of a second charging pump, which had been on manual control, was increased by the operator. The third charging pump was not operating.
9:26 a.m.		
The Shift Supervisor ordered power reduction. One operator fast closed the turbine control valves; another operator commenced normal boration.	4.2.1	The Shift Supervisor was initially in his office which was located off the main operating area of the control room. He was called to the control room by an operator after the first alarm annunciated.
The following alarms were received in the control room: reactor coolant loop low pressure alarm (set-point, 2064 psig); overtemperature ΔT turbine runback because of decreasing pressurizer pressure; main steam dumps armed alarm.	3.2.2 and 4.2.1	The overtemperature ΔT setpoint is a computed value which is a function of pressurizer pressure and reactor coolant system average temperature.

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*All times in this report are given in Eastern Standard Time.

Time and Event	Section Reference	Comment
9:27 a.m. (about)		
All eight main steam dump valves opened automatically.		Steam dump valves opened in automatic control in response to error signal derived from the difference between RCS coolant reference and average temperature.
The third charging pump was manually started by the operator.	3.2.2 and 4.2.1	All three charging pumps were running at this time. The RCS pressure and pressurizer level decreased as a result of flow through the rupture (break flow). The rate of indicated decrease was consistent with the break flow and the combined effects of high charging flow and the RCS swell from the turbine down-power transient.
The containment fan-cooler, service-water discharge radiation monitor (R-16) alarmed.		Alarm probably resulted from the proximity of the instrument to the B main steam line in the Intermediate Building.
9:28 a.m.		
Four main steam dump valves closed automatically		
The following also occurred: pressurizer level low alarm (setpoint, 10.5%); automatic reactor trip on low pressurizer pressure (setpoint 1873 psig adjusted by a rate factor); automatic safety injection (setpoint, 1723 psig); automatic containment isolation as a result of safety injection actuation; main turbine automatic trip on reactor trip; A and B steam generator low level alarms; automatic start of both A and B motor-driven auxiliary feed pumps on safety injection; main feedwater automatic isolation and main feedwater pump automatic trip on containment isolation.	3.2.2	The steam generator low levels resulted from the combined effects of the power reduction, reactor, main turbine and main feedwater pump trips.
	3.2.2 and 3.4	The RCS depressurization rate increased at this time. The break flow had not increased, but the effects of increasing RCS temperature due to the turbine load reduction were no longer present. Further, all charging pumps automatically tripped as a result of safety injection actuation.
	3.2.2	Letdown isolation valve LCV427 closed on low pressurizer level; the inservice orifice isolation valve closed on interlock with LCV427 controls.
	3.2.2	The reactor coolant pump (RCP) seal return line isolated on containment isolation. Leakage through the RCP seals pressurized the seal return piping. As shown by pressurizer relief tank (PRT) level indication, the seal return relief lifted. The contribution of this relief to PRT inventory was insignificant.

Time and Event	Section Reference	Comment
9:29 a.m.		
The main electrical generator output breakers automatically tripped.	3.2.2 and 4.2.1	
Both RCPs were manually tripped.	4.3.2.2(1)	Ginna Emergency Procedures E-1.1 and E-1.4 require tripping RCPs at ≤1715 psig; Westinghouse Owners' Group guidance recommends a lower trip pressure. Licensee requires an RCP trip at a higher pressure because Ginna lacks an environmentally qualified pressure instrument capable of reading these lower pressures.
Pressurizer level indicated about 0%.		
9:29 a.m. (about)		
Both steam supply valves to the turbine-driven auxiliary feedwater pump opened automatically because of low-low level in both steam generators.	3.2.2	
9:30 a.m.		
Four main steam dump valves closed automatically		All steam dumps were now closed.
Initial RCS depressurization stopped at about 1200 psig.	3.2.2	Based on post-event data evaluation, the Task Force concluded a steam bubble may have formed in the reactor vessel upper head at this time.
	3.2.2	Termination of pressure drop was apparently due to the effects of the establishment of saturation conditions in the reactor vessel upper head along with safety injection.
9:32 a.m. (about)		
The B motor-driven auxiliary feedwater pump was secured manually.	3.2.3	
The B steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	3.2.3 and 4.2.1	The turbine-driven auxiliary feedwater pump was now being supplied steam from the A steam generator only.

Time and Event	Section Reference	Comment
9:33 a.m.		
The Shift Supervisor notified the NRC Operations Center via the Emergency Notification System (ENS) phone. The Shift Supervisor reported a reactor trip from 100% power as a result of a steam generator tube rupture. The identity of the faulted steam generator and release information was not given at this time.	4.2.1, 6.1.1, and 6.5.1	The Shift Supervisor made the ENS report using the ENS phone in his office. He suspected that the B steam generator contained the fault but chose to confirm the situation before identifying the faulted steam generator to the NRC. After the initial report, a licensed reactor operator, who was not part of the onshift crew, manned the ENS in the control room.
The Shift Supervisor declared an Unusual Event.	4.2.1 and 6.1.1	The Shift Supervisor declared the Unusual Event during his discussion with the NRC Headquarters Duty Officer; the Plant Superintendent was unaware of this declaration. The declaration of an Unusual Event was made in accordance with the Ginna Emergency Plan Implementing Procedures.
9:35 a.m.		
The NRC Senior Resident Inspector (SRI) arrived in the Ginna control room.	6.5.1	The SRI had been monitoring the ENS in his office since 9:33 a.m.
9:38 a.m.		
NRC Region I was placed in phone communication with the site by the NRC Headquarters Duty Officer (HDO).	6.4.2.2	The connection was via Federal Telecommunications Systems (FTS) from Region I to the NRC Operations Center then via the ENS to the site.
Various main steam dump valves began to cycle open and closed.		Main steam dump valves were now being operated in the pressure-control mode. The operator was manually controlling these valves to cause a plant cooldown as required by the steam generator tube rupture procedure.
9:40 a.m.		
The B main steam isolation valve (MSIV) was manually closed and the B steam generator was isolated as required by the steam generator tube rupture (SGTR) procedure. Plant cooldown was being maintained by dumping steam from A steam generator to the main condenser.	3.2.3 and 4.2.1	Along with closing the MSIV, B steam generator isolation included automatic closure of the feedwater supply, blowdown and sample valves on containment isolation, manual closure of its auxiliary feedwater supply, and manual closure of the steam supply valve from B steam generator to the turbine-driven auxiliary feedwater pump.

Time and Event	Section Reference	Comment
9:40 a.m. (continued)		RCS pressure and reactor vessel upper head temperature data indicated that the steam bubble in the reactor vessel upper head had been essentially collapsed by safety injection flow.
The licensee declared an Alert.	4.2.3.1.1 and 6.1.1	
9:46 a.m.		
The Ginna Plant Superintendent notified the State of New York, Monroe County, and Wayne County.	4.2.3.1.1 and 6.2	
The A steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	3.2.3	The turbine-driven auxiliary feedwater pump was now secured.
9:48 a.m.		
The A motor-driven auxiliary feedwater pump was manually stopped to control A steam generator level.		No feedwater pumps were operating at this time.
9:49 a.m.		
The NRC Headquarters Duty Officer (HDO) notified the Federal Emergency Management Agency (FEMA).	6.5.1	
9:50 a.m.		
The steam generator blowdown radiation monitor (R-19) alarmed.	3.2.3	R-19 monitors radiation levels on a section of the blowdown system piping common to both A and B steam generators. The alarm at this time may have been caused by activity from the B steam generator spreading through the system because of steam generator sample valves that the licensee indicated had a history of leaking.

Time and Event	Section Reference	Comment
9:53 a.m.		
The B steam generator power-operated relief valve (PORV) was manually isolated by an auxiliary operator closing a local, upstream, manual valve.	4.2.1	Operators stated that they manually isolated the B steam generator atmospheric PORV to minimize the potential for a release that would result from high steam generator pressure lifting the PORV. The control room operators interpreted the step in the tube rupture procedure which directed them to place the PORV in the manual closed position to mean that the local manual PORV isolation valve should be closed. Closing this isolation valve made the PORV unavailable for use in reducing B steam generator pressure and resulted in five challenges to an unisolable steam generator safety valve.
9:55 a.m.		
The NRC Region I Incident Response Center was activated.	6.4.2.2	
B steam generator narrow-range level indicated offscale high even though all feedwater supplies to the B steam generator had been isolated earlier in the event.	3.2.3	
9:57 a.m.		
Safety injection initiation circuitry was manually reset; containment isolation was then reset.	3.2.3 and 4.2.1	Safety injection was reset to permit resetting of the containment isolation signal. Containment isolation was reset to permit restoration of instrument air to the containment. Instrument air would be required to operate various valves inside containment, including the pressurizer power-operated relief valves.
9:58 a.m.		
The licensee's Emergency Coordinator declared the Ginna Technical Support Center (TSC) fully operational.	4.2.3.1.1 and 6.1.2	Manning of the TSC had begun about 9:35 a.m.

Time and Event	Section Reference	Comment
9:59 a.m. (about) Instrument air was restored to containment.	3.2.3	Because letdown isolation valve LCV427 fails open on loss of instrument air pressure, it could have opened subsequent to containment isolation. If LCV427 had opened, restoration of instrument air would have caused it to close at this time.
10:00 a.m. A and C condensate pumps were manually stopped.		The B condensate pump was still running.
10:03 a.m. All main steam dump valves were now closed.		
10:04 a.m. One charging pump was manually restarted.	3.2.3 and 4.2.1	
10:07 a.m. As directed by the SGTR procedure, pressurizer PORV PCV430 controls were manually cycled open and closed twice from the control room. RCS pressure, PRT pressure, level and temperature and PORV valve position indication in the control room demonstrated the valve successfully operated.	3.2.4 and 4.2.1	
	3.2.4	Shortly after the PORV was operated, pressurizer level increased above the letdown isolation setpoint. Letdown isolation valve LCV427 and the selected letdown orifice isolation valve then opened. This resulted in lifting the letdown relief valve and adding water to the PRT. The Task Force determined the letdown relief valve was the major contributor to the PRT water level increase.
10:08 a.m. Pressurizer PORV PCV430 controls were manually cycled again from the control room and the valve successfully operated.	3.2.4 and 4.2.1	

Time and Event	Section Reference	Comment
10:09 a.m.		
Pressurizer PORV PCV430 controls were manually cycled again. The valve opened as desired. After the operator placed the controls in the closed position, the valve started to close but then reopened and stuck open.	3.2.4 and 7.4.1	
The operator placed the PORV block valve control switch in the closed position. RCS pressure dropped to about 900 psig; pressurizer level increased rapidly.		
	3.2.4	The rapid rise in pressurizer level exceeded that attributable to safety injection and charging flow and was the first clear indication to the control room staff that a steam bubble had formed in the reactor vessel upper head. This was, in fact, the second time a steam bubble had formed in the upper head region. The bubble grew as RCS pressure dropped.
The pressurizer relief tank (PRT) high-pressure alarm was received in the control room.	3.2.4	
10:10 a.m.		
The PRT high-temperature alarm was received in the control room.	3.2.4	
10:11 a.m. (about)		
PORV block valve PCV516 indicated fully closed; pressurizer level indicated offscale high; safety injection increased RCS pressure.	3.2.4	Operators also closed block valve PCV515 to isolate the other pressurizer PORV, PCV431C.
10:17 a.m.		
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	3.2.5	
10:19 a.m. (about)		
One B steam generator safety valve lifted and closed.	3.2.5	Safety injection and charging flow maintained RCS pressure greater than B steam generator pressure, resulting in continued RCS inleakage into the faulted steam generator. RCS pressure exceeded the lowest setpoint of the B steam generator safety valves (nominally, 1085 psig).

Time and Event	Section Reference	Comment
10:19 a.m. (continued)	3.2.5	The B steam generator safety valve may have closed and then started to leak steam after this first opening.
	4.2.1 and 7.4.6	The B steam generator safety valve position recorder failed to indicate this or subsequent safety valve lifts. The operators heard these lifts from the control room and estimated their duration based on aural information.
10:26 a.m. The PRT high level alarm was received in the control room.	3.2.5 and 4.2.2(5)	
10:28 a.m. (about) One B steam generator safety valve lifted and closed.	3.2.5	
10:29 a.m. The A motor-driven auxiliary feedwater pump was manually stopped.		
10:30 a.m. The NRC Headquarters Operations Center was activated.	6.5.2 and 6.5.3	
10:33 a.m. (about) The licensee dispatched the onsite and offsite radiological survey teams.	5.7 and 6.1.2	The survey teams were formed and dispatched after the Alert declaration instead of the Site Area Emergency declaration as specified in the Ginna Emergency Plan Implementing Procedures. This action was done as a result of procedure improvements identified during the January 21, 1982 emergency drill.
10:34 a.m. The NRC Headquarters Response Coordination Team notified FEMA that the NRC Operations Center had activated.	6.5.1	

Time and Event	Section Reference	Comment
10:35 a.m.		
The NRC Executive Director for Operations notified the NRC Chairman about the event.	6.5.4	
	6.5.2	The NRC Commissioners' Assistants were not notified at this time by the NRC Response Coordination Team, as required by NRC incident response procedures.
10:38 a.m. (about)		
One B steam generator safety valve lifted and closed.	3.2.6	
Safety injection was terminated by the operators to prevent further release through the B steam generator safety valve.	3.2.6 and 4.2.3.1.2	Charging flow was maintained.
10:40 a.m.		
The B condensate pump and the condensate system were secured; the air ejector secured automatically following loss of condensate flow.	3.2.6, 4.2.1, and 4.3.4(2)	The licensee secured the condensate system to minimize the spread of radioactive contamination to the condensate storage tanks (CSTs) and the condensate demineralizer system. Securing the condensate system made the main condenser unavailable for further dumping of steam.
The A steam generator PORV was manually throttled open to continue the plant cooldown by relieving the A steam generator to atmosphere.	3.2.6	
10:42 a.m. (about)		
A second charging pump was started.	3.2.6	
The pressurizer heaters were re-energized to establish a steam bubble in the pressurizer.	3.2.7 and 4.2.1	The pressurizer heaters tripped on low pressurizer level during the initial depressurization.
10:44 a.m.		
The licensee declared a Site Area Emergency and executed a site evacuation.	6.1.1	Nonessential personnel were evacuated to the licensee's training center which was downwind of the plant and within the path of the release plume.

Time and Event	Section Reference	Comment
10:52 a.m. (about)		
The PRT rupture disc ruptured, releasing water to the A containment sump.	3.2.6	The disc ruptured primarily because of the letdown relief flow; pressurizer PORV openings and RCP seal return relief were minor contributors to the PRT level transient which finally caused the disc rupture.
10:59 a.m.		
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.		From this time in the event, until the plant was cooling down on the residual heat removal system, the A motor-driven auxiliary feedwater pump was run intermittently to control A steam generator water level.
11:07 a.m. (about)		
One safety injection pump was manually restarted from the control room. The safety injection pump discharge valve was locally throttled to prevent B steam generator safety valve lifts.	3.2.6 and 4.2.1	The safety injection pump was started in anticipation of an RCS pressure drop that might result from restarting an RCP. This action was not required by the SGTR procedure but was taken as a direct result of the inability to reestablish normal pressurizer pressure control.
11:19 a.m. (about)		
One B steam generator safety valve lifted and closed.	3.2.6	
The process computer failed. It remained out of service until about 11:35 a.m.	3.2.7 and 4.2.3.2	The licensee manually read reactor vessel upper head and core exist thermocouples to verify adequate core cooling and to determine subcooling in the core and reactor vessel upper head.
	3.2.7	Any remaining steam bubble in the reactor vessel upper head region, at this time, would have had a volume of less than 300 ft^3.

Time and Event	Section Reference	Comment
11:21 a.m. (about)		
The A RCP was restarted; reactor vessel upper head thermocouple temperatures approached core exit temperatures; pressurizer level indications remained offscale high.	3.2.7, 4.2.1, and 4.3.4(4)	A steam bubble in the reactor vessel upper head region would have been condensed by the cooler loop water now forced into this region. Since the pressurizer level instruments were calibrated for operating conditions, the actual pressurizer level would have to drop below 80% before indicated level would respond. The pressurizer volume above 80% actual level is approximately 200 ft^3.
One charging pump was stopped.	3.1	
11:25 a.m.		
The licensee's Offsite Emergency Operations Facility was fully operational.	6.1.3.1	
The NRC Chairman arrived at the NRC Headquarters Operations Center.	6.5.4	
11:25 a.m. (about)		
An NRC Headquarters Operations Center representative made initial event notifications to other Federal agencies; e.g., Department of Energy, Health and Human Services, Environmental Protection Agency, and the White House Situation Room.	6.5.5	
11:37 a.m. (about)		
One B steam generator safety valve lifted and closed; the safety injection pump was stopped.	3.2.8	Based on the indicated pressure differential between the RCS and the B steam generator, and on an RCS inventory balance calculation, the Task Force determined the safety valve failed to fully reseat. It remained partially open until about 12:25 p.m., leaking water at a rate estimated to be about 100 gpm.
11:40 a.m.		
The NRC Region I Site Team and FEMA personnel departed for the Ginna site. The NRC Region I Administrator was the NRC Site Team Leader.	6.4.2.2	

Time and Event	Section Reference	Comment
11:43 a.m. (about)		
The plant vent particulate radiation monitor (R-13) and the plant iodine monitor (R-10B) alarmed.	5.4.2.1	The licensee stated that the R-13 and R-10B monitor alarms were probably caused either by increased background radiation in the vicinity of these monitors or by the Auxiliary Building ventilation system drawing outside air into the building after the steam generator safety valve lifts. It should be noted that no plant noble gas radiation monitor (R-14) alarm was received at this time. The reason this alarm did not occur has not been determined.
11:46 a.m.		
Additional NRC offices were notified by personnel in the NRC Headquarters Operations Center; e.g., Commissioners' Assistants (through the Chairman's office), Congressional Affairs.	6.5.2	
11:52 a.m.		
Pressurizer level indications returned on scale; a steam bubble had been reestablished in the pressurizer.	3.2.8	
11:55 a.m.		
The NRC Chairman briefed the New York State Governor on the status of the plant and on planned NRC involvement in the event.	6.5.4	
12:02 p.m.		
Normal letdown was restored.	3.2.8 and 4.2.1	The maximum rate of change of pressurizer level indication, which occurred about 12:10 p.m., agreed well with that predicted by analysis of the effects of the existing cooldown, charging and letdown rates and the break flow predicted by the Task Force model.
12:12 p.m. (about)		
One safety injection pump was started from the control room.	3.2.8	The safety injection was restarted to terminate the rapid decrease in pressurizer level. The pump was operated intermittently over the next 23 minutes to control pressurizer level.

Time and Event	Section Reference	Comment
12:27 p.m. The RCS and B steam generator indicated pressures equalized.	3.2.9	The B steam generator pressure trend indicated that the B steam generator safety valve reseated completely just before this time.
12:34 p.m. (about) The RCP seal water return isolation valve was manually opened.		RCP seal return relief reseated at this time.
12:35 p.m. (about) Intermittent operation of the safety injection pump was stopped.	3.2.9	
1:16 p.m. The A MSIV was manually closed.		
1:30 p.m. The NRC Chairman updated the New York State Governor on plant status and discussed with him the benefits of the state conducting offsite confirmatory radiological monitoring.	6.5.4	
1:52 p.m. The NRC Chairman discussed offsite confirmatory monitoring capabilities with a representative of the New York State Radiological Health Department.	6.5.4	
2:00 p.m. The licensee reported containment sump A level as 9.3 feet (approx. 8000 gallons); PRT level at 92%.	7.4.5	Containment sump A has two channels of level indication. Channel 1 indicated 5.3 feet (1,900 gallons); channel 2 indicated 9.3 feet (8,000 gallons). Later, it was discovered that channel 2 was in error.
3:25 p.m. The NRC Chairman appointed the NRC Executive Director for Operations as Acting Executive Team Director and left the NRC Headquarters Operations Center.	6.5.4	

Time and Event	Section Reference	Comment
4:15 p.m.		
The NRC Region I Incident Response Site Team arrived onsite at Ginna.	6.4.2.2	The delay in the Site Team reaching the Ginna site resulted from poor weather conditions in the Rochester area.
5:00 p.m.		
The NRC Region I Administrator was appointed Director of Site Operations (DSO) with full authority to act for the Commission at the site.	6.4.2.2 and 6.5.4	New York State Governor, NRC Chairman, the other NRC Commissioners, and other federal and state agencies were notified of the transfer of authority to the DSO.
6:40 p.m. (about)		
Narrow-range water level indication for the B steam generator returned to the indicating range. Plant cooldown continued via the A steam generator PORV with the A RCP providing flow through the A loop and backflow through the B loop. The operators maintained indicated RCS pressure 25 psi below B steam generator pressure. The B steam generator was being cooled by intermittently feeding it with auxiliary feedwater while bleeding it via the ruptured tube to the RCS.	3.2.9	
	4.2.1	The plant staff was concerned that water in the B main steam line might flash to steam if the steam generator was cooled and depressurized too quickly. Flashing in the main steam lines could have caused a water hammer, which could have overstressed the main steam line hangers. Therefore, the plant staff decided to pin these hangers and to conduct a slow cooldown.
	3.2.9	Because of an instrument calibration error in the RCS loop pressure instrument, the actual RCS-to-B steam generator pressure differential was about 3 psi and very little steam generator-to-RCS flow existed.

Time and Event	Section Reference	Comment
6:40 p.m. (continued)	3.2.9 and 4.3.1	To provide warning of excessive boron dilution in the RCS as a result of the B steam generator feed-and-bleed process, the plant staff sampled the RCS for boron concentration at half-hour intervals. The feed-and-bleed cooldown process caused the level in the CVCS Holdup Tanks to increase and the the plant staff discussed the consequences of these tanks filling. The capacity of these tanks was not approached.
7:04 p.m.		
An operator again attempted to shut pressurizer PORV PCV430; the valve remained open.		
7:17 p.m.		
The licensee downgraded the Site Area Emergency to an Alert.	6.1.1	
January 26, 1982		
7:00 a.m. (about)		
The residual heat removal (RHR) system was placed in service to continue the plant cooldown. The A RCP remained in operation.	3.2.9, 4.2.1, 4.2.3.3.2, and 7.1	The RCP remained in operation to assist in RCS degasification and cleanup in preparation for opening the primary-side manway on B steam generator. At low steam pressures in the A steam generator, the capacity of the A steam generator PORV had limited the plant cooldown rate.
10:45 a.m.		
The licensee downgraded the Alert to the Recovery phase.	4.2.1 and 6.1.1	Chapter 7 discusses occurrences after this time.

3 PLANT SYSTEM RESPONSE

3.1 Introduction

The plant response to the January 25, 1982 steam generator tube rupture at Ginna involved interaction among many systems, subsystems, and components. In order to present a clear picture of the response of the plant systems, the following sections have been written to provide an overview of system response during nine distinct phases of the event. These phases were chosen to represent periods of time during which no major changes occurred in the use of important systems or in the trends of the major thermal-hydraulic parameters.

The steam generator tube rupture event of January 25, 1982 has been divided into the following nine phases:

(1) steady-state operation

(2) tube rupture and initial depressurization

(3) natural circulation and reactor coolant system repressurization

(4) pressurizer power-operated relief valve operation

(5) prolonged safety injection

(6) safety injection termination and leakage reduction

(7) reactor coolant pump restart

(8) leaking steam generator safety valve

(9) leak termination and cooldown

These nine phases are described in Section 3.2 and are shown on the graph of reactor coolant system and steam generator pressures versus time (Figure 3.1). Figures 3.2 through 3.4 present the reactor coolant system and steam generator water levels versus time, cold-leg temperatures versus time, and pressurizer relief tank response versus time. Figures 3.5 and 3.6 present the Task Force's estimates of steam generator tube leakage and safety injection and charging flow versus time. Table 3.1 presents a summary of the system conditions during each phase.

Section 3.3 presents a description of the plant system; Section 3.4 discusses the Task Force's estimate of the leak rate; Section 3.5 discusses the system temperature distribution and thermal shock potential; Section 3.6 provides system mass balance estimates; and Section 3.7 gives a comparison with steam generator tube rupture events at other plants.

3.2 Description of the Nine Phases of the Event

3.2.1 Phase 1--Steady-State Operation
(Period before 9:25 a.m, 1/25/82)

Prior to 9:25 a.m., January 25, 1982, the plant was operating at full-power, steady-state conditions. The major primary and secondary system parameters and their steady-state values are listed in Table 3.2. These parameters indicate that the plant was in a normal condition with no important systems out of service and no abnormal conditions in any of the important system parameters. The Task Force did not identify any conditions or information which would have indicated that a steam generator tube rupture was to be expected.

3.2.2 Phase 2--Tube Rupture and Initial Depressurization
(Period from 9:25 a.m. to 9:30 a.m., 1/25/82)

At 9:25 a.m., there was a sudden rupture of a single tube in the B steam generator. Detailed information from the plant process computer is available for the period beginning at 9:26 a.m. This information was used to develop the graphs of pressurizer (PZR) pressure and level versus time (Figure 3.7). The initial depressurization from 2197 psig to approximately 2100 psig and the associated drop in pressurizer level from 47% to 30% occurred between 9:25:25 a.m. and 9:26:30 a.m. The depressurization and level drop were terminated by automatic and manual actions to increase the charging flow from 30 gpm to at least 60 gpm (corresponding to full flow from one charging pump) and thermal expansion of the water in the reactor coolant system associated with the manual and automatic load reduction. This indicates that the initial leak rate was approximately 750 gpm.

A level deviation alarm resulted when the water level in the B steam generator exceeded its programmed setpoint of 52% by 7%. The water level increased because of the flow from the reactor coolant system to the steam generator through the ruptured tube. The increased water level was sensed by the feedwater control system, which reduced feedwater flow by modulating the feedwater control valve. The difference between feedwater and steam flows produced the steam-flow/feed-flow mismatch alarm from this B steam generator. Simultaneously, a radiation alarm on the air ejector indicated that a leak from the reactor coolant system to the secondary system had occurred. These were extremely important symptoms of a tube rupture in the B steam generator.

At 9:27:11 a.m. a more rapid reactor coolant system depressurization and level decrease began. This was the result of a reactor coolant system cooldown and a continuing leak of approximately 750 gpm. A discussion of the Task Force's leak rate estimate is included in Section 3.4. This leak resulted in a reactor trip at 9:28 a.m. on low pressurizer pressure (∿1900 psig), an automatic safety injection actuation signal on low pressurizer pressure (∿1720 psig), and a containment isolation signal on safety injection actuation. The safety injection actuation signal started all three high pressure safety injection pumps and the two motor-driven auxiliary feedwater pumps. The containment isolation signal resulted in the closure of all containment isolation valves, termination of main feedwater flow, and termination of charging flow. The turbine-driven auxiliary feedwater pump subsequently started automatically on low water level (17%) in both of the steam generators. Shortly after these actuation signals, the pressurizer emptied of water, and the reactor coolant system pressure

Table 3.1 Summary of system conditions for each phase of the Ginna event

System & Parameter	Phase 1 Before 9:25 am	Phase 2 9:25-9:30 am	Phase 3 9:30-10:07 am	Phase 4 10:07-10:15 am	Phase 5 10:15-10:38 am	Phase 6 10:38-11:21 am	Phase 7 11:21-11:37 am	Phase 8 11:37-12:27 pm	Phase 9 After 12:27 pm
RCS	Normal operation	Depressurizing	Pressurizing	Steam bubble formation	Represurized	Reduced pressure	Forced circulation	Continuing leakage	Cooldown
Pressure control	Pressurizer operating	Break flow	Break & SI pump flow	Upper head vaporizing	Break & SI pump flow	Break & charging pump flow	Break & charging pump flow	Break & charging pump	Pressurizer operating flow
PZR	47% full	Draining	Empty	Filling	Full	Full	Full	Returns to normal	Controlled level
RCPs	On	Tripped 9:29 am	Off	Off	Off	Off	A on	A on	A on
PORV	Closed	Closed	Closed	4 opening	Stuck open	Stuck open	Stuck open	Stuck open	Stuck open
PORV block valve	Open	Open	Open	Closed	Closed	Closed	Closed	Closed	Closed
Charging flow	On	On	Off	On	On	On	On	On	On
SI pumps	Off	All automatically started 9:28 am	All on	All on	All on	All off, 1 restarted 11:07 am	1 on	Off, then 1 cycled	Off
Letdown system	Operating	Isolated 9:28 am	Isolated	Isolated	Isolated	Isolated	Isolated	Isolated	Operating
RCS to SG B leakage (gpm)	None detected	750	400	400 to -200	350	150	150 to 250	200	-32 to 0
RCS to SG B pressure difference (psid)	1400	1400 to 400	300 to -150	300	320	50	30	140	-1
SG A	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
Main FW	On	Tripped, isolated 9:28 am	Off	Off	Off	Off	Off	Off	Off
Auxiliary FW	Off	Started 9:28 am	Throttled, then off	Restarted, then off	On	Restarted	Operated as needed	Operated as needed	Operated as needed
Steam to condenser	Operating	Operating	Operating	Operating	Operating	Isolated 10:40 am	Isolated	Isolated	Isolated
Steam dump to atmosphere	No	No	No	No	No 10:40 am	Initated	Throttled	Throttled	Throttled
Safety valves	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
SG B	Operating	Operating with leakage	Isolated 9:40 am with leakage	Isolated with leakage	Isolated with leakage	Isolated with leakage	Isolated with leakage	Isolated with leakage	Isolated with SG to RCS leakage
Main FW	On	Tripped & isolated 9:28 am	Off	Off	Off	Off	Off	Off	Off
Auxiliary FW	Off	Started 9:28 am	Stopped 9:46 am	Off	Off	Off	Off	Off	Operated as needed
Steam to condenser	Operating	Operating	Isolated 9:40 am	Isolated	Isolated	Isolated	Isolated	Isolated	Isolated
Steam dump to atmosphere	No	No	No	No	No	No	No	No	No
Safety valves	Closed	Closed	Closed	Closed	2 openings	2 openings	1 opening	Leaking	Closed
Instrument air inside containment	Operating	Isolated 9:28 am	Operation restarted 9:59 am	Available	Available	Available	Available	Available	Available
Pressurizer heaters	Operating	Off	Off	Off	Off	Energized	Operating	Operating	Operating
Pressurizer spray	Operating	Off	Off	Off	Off	Off	Available	Available	Available

Table 3.2 Ginna system parameters

Parameter	Value
General:	
Licensed power MWt	1520
Plant capacity, MWe	490
Loop number	2
Loop isolation valves, number	0
Steam Generators (S/Gs):	
Secondary water volume:	
Full load, ft^3	1681
No load, ft^3	2821
Level at full load, %	52
at zero load, %	39
Secondary steam volume	
Full load, ft^3	2898
No load, ft^3	1758
A S/G to MSIV, ft^3	776
B S/G to MSIV, ft3	1055
Steam pressure:	
Full load, psig	755
No load, psig	1055
Primary water volume, ft^3	944
U-tubes, each S/g, no.	3260
Allowed leakage, gpm	0.1
Svs/S/G, number	4
Setpoints for each SV, psig	1085, 1140 1140, 1140
Flow rate, each S/G, lb/h	3.3×10^6
Flow rate, each SV, lb/h at 1100 psig	0.82×10^6
PORVs each S/G:	
Number	1
Operation	Automatic at ≤1050 psig or manual
Total capacity, % power	10
Steam dump, bypass to condenser:	
Operation	$T_{AVE} - T_{REF}$ pressure control
Total capacity, % power	40
Auxiliary Feedwater (AFW) Pumps:	
Motor-driven	
Number	2
Capacity (each), gpm	200
Automatic start signals:	1
Low-low level in S/G	
Trip of main FW pumps	
SIS	
Auxiliary Feedwater (AFW) Pump, Turbine-driven	
Number	1
Capacity gpm	400
Automatic start signals:	
Low-low level	Both S/Gs
Loss of power	Both 4-kV buses
Standby AFW Systems	Manual
MSIV Automatic Closure Modes, All Lines:	
(1) High-high steam flow, lb/h, and SIS	3.6×10^6
(2) High steam flow, lb/h low T_{AVE}, °F, and SIS	0.4×10^6; 545
(3) High containment pressure, psig	18
MSIV closure times, sec	5
Charging System	
Charging pumps, number	3
Charging pumps, type	Positive displacement
Design flow, gpm	60
Normal charging flow, gpm	30
Normal letdown flow, gpm	40
Normal RCP seal supply flow, gpm	16
Normal RCP seal return flow, gpm	6
Automatic letdown isolation	Low pressurizer level
Automatic trip	Safety injection

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Table 3.2 continued

Parameter	Value
Reactor Coolant System:	
Total volume, ft^3	6245
Total RCS flow, lb/h	64.3×10^6
Pump thermal input, Btu/hr	30×10^6
T_{AVE}	
Full load, °F	573
No load, °F	547
ΔT, full load, °F	56
Reactor vessel head temp., °F	590
Nominal system pressure, psig	2200
Low pressure scram set-point, psig	1873
Pressurizer:	
Volume, total, ft^3	800
Water volume, full load, ft^3	480
Total heater capacity, kW	800
Restrictions on spray nozzle, ΔT_{MAX}, °F	320
Pressurizer PORVs:	
Number	2
Set pressure, psig	2335 or manual
Flow rate, lb/h	1.79×10^6
Pressurizer Relief Tank:	
Rupture disc design, psig	100
Capacity, ft^3	800
Pressurizer Safety Valves:	
Number	2
Operating pressure, psig	2485
Flow rate, lb/h, at 2500 psig	0.288×10^6
Pressurizer Level:	
Full load, %	47
No load, %	22
Safety Injection Actuation setpoints:	
Low pressurizer pressure, psig	1723
High containment pressure, psig	4
Low steamline pressure, psig	514

Parameter	Value
High pressure safety injection	
Number	3
Type	Centrifugal
Design flow, gpm	300
Shutoff pressure, psig	1520
Boron injection, with SIS	Pumps take suction from BAST then from RWST
Accumulators:	
Number	2
Pressure, psig	700
Refueling Water Storage Tank:	
Capacity, gal	3.38×10^5
Boron concentration, ppm	>2000
Design pressure, psig	121
Boric Acid Storage Tanks:	
Number	2
Capacity, gal each	3600
Boron concentration, ppm	20,000
Main Feedwater Pumps:	
Type	Centrifugal
Number	2
Capacity	50% full power
Flow rate, gpm	14,000
Operating pressure, psig	853
Shutoff head, psig	1180
Drives	Electric
Isolation signals	
S/G level, %	67
Safety injection actuation	
Trips	1. Loss of offsite power 2. Overcurrent 3. Thermal reload

dropped to approximately 1200 psig. The minimum system pressure was apparently determined by the temperature of the hottest fluid in the reactor coolant system. This fluid would have flashed (vaporized) when the system pressure dropped below the saturation pressure corresponding to its temperature. This initial flashing in the reactor coolant system would have occurred when the temperatures in the pressurizer surge line and reactor vessel upper head were near or above 576°F, the saturation temperature corresponding to 1270 psig. Therefore, steam generation probably occurred in both locations.

Immediately after the reactor turbine and feedwater trips, the narrow-range A and B steam generator water level instruments indicated a level drop from about 47% to about 10%, while the wide-range level instruments indicated a slight increase in level. This discrepancy was believed to result from the cold calibration of the wide-range instrument and the fact that its lower pressure tap was located just above the tube sheet. The narrow range instrument is calibrated at the operating temperature of the steam generator and its lower pressure tap is located just above the top elevation of the tube bundle (see Figure 3.11).

Approximately 50 sec after the safety injection signal occurred, the reactor operators verified that the pressurizer pressure was less than 1715 psig and manually tripped the reactor coolant pumps in accordance with the Ginna plant procedures.

During normal operation, both seal injection and component cooling water are provided to the reactor coolant pumps. The seal injection flow was terminated upon safety injection because the charging pumps were tripped automatically.

In addition, the piping that returns the seal water to the chemical and volume control system (CVCS) was isolated by the containment isolation signal. After the seal return valve closed, reactor coolant system leakage through the reactor coolant pump seals pressurized the seal return line. As shown by the pressurizer relief tank water level indication, the relief valve on this line lifted. The pumps can be operated without seal injection provided component cooling is available and the seal leakage is less than 5 gpm (Ginna Procedure

P-2--Reactor Coolant System Precautions and Limitations). Therefore, the reactor coolant pump trip was a result of the procedural requirement to trip the pumps to avoid exacerbating certain small-break loss-of-coolant accidents.*

Numerous valves inside containment were affected when the instrument air was isolated at 9:28 a.m. The important valves for this event were the two pressurizer PORVs, the pressurizer spray valves, the CVCS charging and letdown valves, and the pressurizer auxiliary spray valve. Except for the level control valve (LCV427) in the CVCS, all these valves fail in the closed position. The pressurizer PORVs have a backup nitrogen supply that is available to operate the valves without instrument air.

3.2.3 Phase 3--Natural Circulation and Reactor Coolant System Repressurization (Period from 9:30 a.m. to 10:07 a.m., 1/25/82)

Following the initial depressurization, the safety injection pumps injected water into the reactor coolant system, increasing the volume of water in the system and increasing the system pressure to 1350 psig. During this period, the reactor coolant system-to-B steam generator pressure difference was approximately 300 psi and the leakage into the B steam generator continued at a rate of approximately 400 gpm. Figure 3.8 presents the Task Force's estimates of safety injection flow and break flow versus pressure. This figure indicates that the reactor coolant system and B steam generator should establish a dynamic equilibrium between injection flow and break flow with a reactor coolant system pressure of 1410 psig, which corresponds to an indicated reactor coolant system pressure of 1385 psig. (The pressure instrument calibration error is discussed in Section 3.2.9.) This condition developed at approximately 10:00 a.m. during the event.

The temperature difference from the cold legs to the hot legs initially decreased, since the reactor trip caused a rapid drop in the reactor core heat generation, and reached a minimum value of 2°F. Following the reactor coolant pump trip at 9:29 a.m., the reactor coolant loop flow rates decreased. As flow decreased, natural circulation developed, with the reactor core as the heat source, and the elevated steam generators as the heat sink.

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*See NUREG-0623, "Generic Assessment of Delayed Reactor Coolant Pump Trip During Small Break Loss-of-Coolant Accidents in Pressurized Water Rectors," U.S. Nuclear Regulatory Commission, November 1979.

At 9:32 a.m. the turbine-driven auxiliary feedwater pump steam supply valve from the B steam line was manually closed in accordance with the steam generator tube rupture procedure. In addition, the B motor-driven auxiliary feedwater pump was isolated from the B steam generator. To confirm that the tube leak was in the B steam generator, as suspected, a check of the B steam line radiation level was made using a portable radiation monitor. The indicated reading on this portable monitor (approximately 30 mrem per hour) gave positive identification of the affected steam generator approximately 15 minutes after the initial alarms had indicated that a problem existed.

At 9:40 a.m. the B steam generator was isolated by closing the MSIV, and no further cooling was taking place in the B steam generator tubes. This caused the flow in the B reactor coolant loop cold leg to stagnate and to reverse direction as water in the B loop cold leg was drawn toward the ruptured tube. The reverse flow in the B reactor coolant loop cold leg continued throughout the event.

Prior to 9:40 a.m., the reactor coolant leaking into the B steam generator was circulated throughout the main steam, main feedwater, and condensate systems. After 9:40 a.m., the B steam generator main steam isolation valve was closed and the tube leak caused an increase in the indicated steam generator water level. The pressure in the B steam generator began to increase when the turbine-driven auxiliary feedwater was terminated at 9:46 a.m. The B steam generator narrow range water level indication went off scale high (over 100% level) at 9:55 a.m. The B steam generator continued to be filled after that time. Later the attached main steam line also flooded.

Throughout this phase, the A steam generator continued to dump steam into the main condenser. The reactor coolant system cooldown rate during this period can be seen by observing the change in the A loop temperature versus time in Figure 3.3.

The only radiation alarm from the steam generator blowdown system occurred at 9:50 a.m., 22 minutes after the B steam generator blowdown piping isolation valve closed on containment isolation. The radiation monitor is located downstream of the sample-line isolation valves, which were also closed upon containment isolation. The licensee indicated that the sample-line isolation valves had a history of leakage problems. The absence of a radiation alarm early in the event may be attributable to the relative locations of the blowdown pipe suction and the tube rupture, to incomplete mixing of the feedwater flow near the tubesheet, and to isolation of the blowdown piping on containment isolation.

The safety injection was reset at 9:57 a.m., after which time the containment isolation system was also reset in order to restore instrument air and gain control of air-operated valves inside of containment. Instrument air, the preferred system for controlling the pressurizer PORV, was restored at about 9:59 a.m.

At 10:04 a.m., one charging pump was restarted, although the steam generator tube rupture procedure called for the starting of all available charging pumps.

3.2.4 Phase 4--Pressurizer Power-Operated Relief Valve Operation (Period from 10:07 a.m. to 10:15 a.m., 1/25/82)

Reduction in the reactor coolant system pressure to reduce the tube leakage is an important step in recovery from a tube rupture event. The first attempt to reduce reactor coolant system pressure occurred at 10:07 a.m. when one pressurizer power-operated relief valve (PORV) was opened for a few seconds. The valve was successfully cycled (opened and closed) three times but failed to close on the fourth cycle at 10:09 a.m. The operators then closed the block valve to terminate flow through the stuck-open PORV. The normal closure time for the block valve is approximately 35 seconds. The plant process computer printout shows that pressure in the reactor coolant system was increasing at

[redacted]

10:11 a.m., indicating that the block valve was closed by that time. In addition, the temperature rise in the pressurizer relief tank (which receives the fluid from the PORV) terminated at 10:12 a.m., indicating no further input from the PORV.

While the PORV was open, the reactor coolant system pressure dropped from 1350 psig to 850 psi. For the period from 10:09 a.m. to 10:11 a.m. the reactor coolant system pressure was lower than the B steam generator pressure. This low reactor coolant system pressure caused a temporary reversal in the primary-to-secondary break flow, an increase in safety-injection flow, and flashing (steam formation) of the water in the reactor vessel upper head and B steam generator tubes.

While the PORV was stuck open the pressurizer level increased rapidly from 6% to 100%. The sources of water available to fill the pressurizer included: water displaced by steam formation in the reactor vessel upper head, water displaced by steam formation inside the B steam generator tubes, flow from the B steam generator into the reactor coolant system through the ruptured tube, and safety injection and charging flow. Table 3.3 presents the Task Force's estimates of the water volume available from each of these sources during the time period from 10:09 a.m. to 10:11 a.m., the period over which the pressurizer filled.

Table 3.3 Task Force estimate of the water sources available to fill the pressurizer between 10:09 a.m. and 10:11 a.m.

Source	Water volume, ft^3
Water displaced by reactor vessel upper head steam bubble	300
Water displaced by B steam generator tube steam bubble	165
Safety-injection flow	250
Flow from B steam generator through the break	35
Charging pump flow	15
Total	765

The indicated rate of increase of pressurizer level, beginning at 10:09 a.m., corresponds to a computed water inventory rate of change of 405 ft^3/min. Since the PORV was opened for about 2 minutes after 10:09 a.m., approximately 810 ft^3 of water would have left the pressurizer. This value is reasonably close to the estimated value of water volume available, that is 765 ft^3.

Since the water volume in the pressurizer at 10:09 a.m. was approximately 100 ft^3, these calculations imply that a relatively small volume (35 to 110 ft^3) of water was discharged through the PORV after the steam in the pressurizer had been relieved.

A review of the level change in the pressurizer relief tank (which accepts fluid from the PORV) indicates that the 4% level increase during the PORV openings corresponds to approximately 40 ft^3 of water. Since the mass of steam in the pressurizer at 10:07 a.m. (i.e., 700 ft^3 of steam at 1350 psig) corresponded to 35 ft^3 of water at 140°F, the indicated increase in pressurizer relief tank level implies that only 5 ft^3 of water was discharged through the PORV. Therefore, all the available data indicated that when the PORV failed to close it was experiencing steam discharge; that very little liquid discharge took place; and that the liquid discharge occurred at the end of the blowdown while the PORV block valve was closing.

During the time when the PORV was open the indicated cold-leg temperature in the B reactor coolant system loop decreased rapidly to 260°F and then recovered to 350°F. As discussed in Section 3.5, these changes are associated with increase and decrease in safety injection flow in the B loop cold leg. The safety injection water was mixing with hot water from the reactor vessel downcomer and the B loop cold-leg temperature sensor was reading a mixed fluid temperature.

After the pressurizer PORV block valve was closed, the system pressure returned to approximately 1400 psig. This pressure was slightly higher than the pressure recorded before the PORV openings. Except for forming the steam bubble in the upper head and filling the pressurizer with water, the system conditions after the block valve closure were essentially the same as before the PORV opening.

After the operator noted that the PORV block valve indicated closed on the control panel, he directed that the PORV tailpipe temperatures be monitored to ensure that the block valve had fully closed and that the other PORV was not leaking. The drop in tailpipe temperatures was slower than expected, so the operator closed the block valve associated with the other PORV. Later, the licensee determined there was, in fact, no leakage past the originally closed block valve or the second PORV.

Throughout this phase of the event, the reactor coolant system was being cooled by dumping steam from the A steam generator to the main condenser. Auxiliary feedwater for the A steam generator was supplied by the A motor-driven pump from the condensate storage tank.

Instrument air had been restored at 9:59 a.m., but the selected letdown orifice isolation valve (LCV200B) and level control valve (LCV427) remained closed because the pressurizer level was below 10%. At approximately 10:08 a.m., the pressurizer level increased and LCV427 and the selected letdown orifice isolation valve opened as designed. The letdown containment isolation valve (AOV371) remained closed, since the valve does not automatically open when the containment isolation signal is reset. Consequently, the letdown line was communicating with the reactor coolant system while the downstream portion of the letdown line remained isolated, and the relief valve (203) opened at a set pressure of 600 psig. This valve relieves to the pressurizer relief tank and was the major contributor to the pressurizer relief tank level increase.

3.2.5 Phase 5--Prolonged Safety Injection
(Period 10:15 a.m. to 10:38 a.m., 1/25/82)

When the reactor coolant system pressure and the pressurizer level increased after the PORV block valve was closed at 10:11 a.m., the conditions necessary for allowing termination of safety injection existed. The plant operators knew, however, that a steam bubble had formed under the reactor vessel upper head, and they were reluctant to interpret the high pressurizer level as a legitimate indication of having sufficient reactor coolant system inventory. As a result, the termination of safety injection did not occur until about 10:38 a.m., after discussions were held between the control room personnel and the Technical Support Center personnel.

A detailed review of the system data by the Task Force indicate that PORV operation was successful in decreasing reactor coolant system pressure and in increasing the liquid inventory by safety injection and charging flow. Subsequently, safety injection increased the reactor coolant system pressure to 1390 psig. Safety-injection flow could have been safely terminated immediately after the PORV block valve closed at 10:11 a.m.

After 10:11 a.m. the continued safety injection caused the reactor coolant system pressure to remain approximately 300 psi above the B steam generator pressure. This pressure differential caused the leakage from the reactor coolant system to the steam generator to persist. As a direct result of the leakage into the B steam generator, the pressure increased to 1080 psig at 10:19 a.m., and the opening of a steam generator safety valve released steam into the atmosphere. This occurred again at 10:28 a.m. The first and second steam generator safety valve openings each resulted in pressure reductions of approximately 50 psi. [Note: Task Force analysis of the B steam generator and reactor coolant system pressure responses suggested that the Code safety valve may have leaked steam after its first opening. This leakage was not reported by the licensee nor has it been confirmed by calculations.] The A and B steam generator valve position recorders were started manually by a technician earlier in the event, but the recorders failed to indicate these and subsequent valve lifts. This failure is discussed further in Chapter 7.

The repeated openings of the steam generator safety valve led the control room and Technical Support Center personnel to decide to terminate safety injection.

3.2.6 Phase 6--Safety Injection Termination and Leakage Reduction (Period 10:38 a.m. to 11:21 a.m., 1/25/82)

The safety injection pumps were stopped at 10:38 a.m. and the reactor coolant system pressure decreased to approximately 950 psig. The secondary pressure continued to decrease to approximately 850 psig as a result of the third opening of the steam generator safety valve. This steam generator pressure reduction of approximately 200 psi is unusually large and indicates that this valve did not close normally, possibly as a result of discharging two-phase flow. With the resulting reactor coolant system to steam generator pressure difference of 100 psi, the leak rate was reduced to approximately 150 gpm. As a result of the continuing leakage, the pressure difference between the reactor coolant system and the B steam generator gradually decreased over the next 40 minutes, falling to 30 psi at about 11:19 a.m.

At about 10:40 a.m., the pressurizer heaters were re-energized to establish a steam bubble in the pressurizer. The pressurizer heaters had tripped on the occurrence of pressurizer low level during the initial depressurization.

At about 10:42 a.m., a second charging pump was started. As indicated in Figure 3.1, the equilibrium reactor coolant system pressure was approximately 40 psig above the pressure in the B steam generator with the two charging pumps running. Continued charging flow while letdown flow remained isolated caused the reactor coolant system-to-steam generator pressure differential to persist and the break flow to continue.

During this phase of the event, the method of dumping steam from the A steam generator was changed to allow steam to be vented to the atmosphere through the atmospheric PORV on the A steam generator's steam line. The steam had been dumped to the condenser until the last operating condensate pump was secured at 10:40 a.m. Without condensate flow, the air ejector automatically secured, and the vacuum in the condenser was not maintained. The decision to terminate the dumping of steam to the condenser was made to prevent any further contamination of the condensate system, particularly the condensate demineralizers.

Also, during this phase of the event, the reactor coolant system pressure increased from 950 to 1050 psig. Initially the increase was caused by operators throttling closed the A steam generator PORV with a corresponding decrease in heat removal from the reactor coolant system. After 11:07 a.m., when one of the safety injection pumps was restarted, the reactor coolant system pressure increased when the safety injection pump added water. The safety injection pump had been restarted as a precaution against a large pressure reduction which could be caused by the restart of the A reactor coolant pump.

One B steam generator safety valve opened a fourth time (at 11:19 a.m.) as a direct result of the reactor coolant system pressure increase caused by the operation of a safety injection pump.

During this phase, both the letdown line relief valve and the seal return relief valve continued to lift and discharge to the pressurizer relief tank. As shown in Figure 3.4, the pressurizer relief tank water level indications demonstrated that the letdown relief valve was the major contributor to the tank inventory increase, which resulted in the burst of the tank rupture disc at about 10:52 a.m. The letdown relief valve remained open until 12:02 p.m. The Task Force estimated the flow rate through the letdown relief valve to be about 24 gpm based on the rate of change in pressurizer relief tank level indication between 10:15 and 10:45 a.m., 22 gpm based on a total pressurizer relief tank and containment sump A inventory balance.

3.2.7 Phase 7--Reactor Coolant Pump Restart
(Period from 11:21 a.m. to 11:37 a.m., 1/25/82)

This phase of the event began with the restart of the reactor coolant pump at about 11:21 a.m. No detailed information is available for the period immediately before or immediately after the time when the pump was restarted because of computer failure.

Although there are no computer-recorded data for the period during the pump restart, later computer data (about 12 minutes after pump restart) and handwritten logs of the thermocouple data indicated that the temperature reduction in the upper head region was very rapid and occurred very soon after the restart of the reactor coolant pump. All the data after the time of pump restart showed that, with the exception of the pressurizer, the entire reactor coolant system was at approximately the same temperature for the rest of the event.

The reactor vessel upper head temperatures had been below the saturation temperature corresponding to the reactor coolant system pressure since 10:11 a.m. but were significantly higher than the temperatures in the remainder of the reactor coolant system, with the exception of the pressurizer. At 11:21 a.m., a steam bubble of less than 300 ft^3 may still have existed in the upper portion of the reactor vessel upper head. There is no instrumentation at higher elevations which would detect such a bubble. After the reactor coolant pump restart the indicated temperature in the upper head decreased to a value equal to the temperatures in the remainder of the reactor coolant system; that is, approximately 400°F. With the reactor coolant pump running and more than 100°F subcooling at the upper head thermocouple locations, it is extremely unlikely that any steam existed in the upper head at this time or later.

The limited data available indicate that it is likely that a small reactor coolant system to steam generator differential pressure, perhaps 40 psid, existed throughout this period. The corresponding leak rate would be 100 gpm.

Throughout this phase of the event, one safety injection pump was operated as a precaution against an uncontrolled depressurization associated with the reactor coolant pump restart. Such a depressurization was of concern to the plant staff because the pressurizer level was still off-scale and a steam bubble was thought to exist in the reactor vessel upper head. It should be noted that the B steam generator would have provided water through the ruptured tube to help suppress any large pressure changes. The primary results of operating the safety injection pump were the two additional openings of the B steam generator safety valve. These openings of the valve will be discussed further in the next phase of the event. The depressurization associated with the reactor coolant pump restart was limited to about 100 psi, apparently as a result of steam formation in the pressurizer (above the range of indicated levels) and increased safety-injection flow.

3.2.8 Phase 8--Leaking Steam Generator Safety Valve
(Period from 11:37 a.m. to 12:27 p.m., 1/25/82)

At 11:37 a.m., the B steam generator's safety valve opened for the fifth time, as a result of the continuing safety injection flow. The data indicated that the valve did not close until pressure in the steam generator decreased to 840 psig. This value is about the same as that for one of the earlier valve openings and is considerably below the pressure at which the valve would normally close. This abnormal behavior may again be attributed to the fact that the valve discharged liquid rather than the steam for which it had been designed.

After the B steam generator safety valve closed, the pressure differential between the reactor coolant system and the B steam generator was more than 100 psid.

Safety injection flow was terminated at about the same time as this last valve opened. However, the reactor coolant system to steam generator differential pressure was significantly higher than for the comparable conditions at 10:38 a.m. Three additional facts indicate that this phase is significantly different from earlier phases of the event. First, the reduction in B steam generator pressure at approximately 12:05 p.m., while the reactor coolant system pressure was more than 100 psi higher, cannot be explained unless there was significant mass or energy removal from the steam generator. Cooling of the B steam generator was in progress this time; however, the observed rate would not support such a pressure difference. Second, the indicated differential pressure implies a large flow, estimated to be 100 to 200 gpm, into the steam generator over a long period of time (50 min). Since the B steam generator appears to have been full at 11:37 a.m. (the time of the last valve opening), it appears very unlikely that the steam generator could accommodate an additional 5,000 to 10,000 gallons of water. Third, the rapid increase in the B steam generator pressure at about 12:25 p.m. was similar to that experienced when the safety valve closed earlier in the event. These facts lead the Task Force to conclude that it is very likely that the B steam generator safety valve failed to fully reseat following the opening at 11:37 p.m. and that the valve leaked at a rate of 100 gpm to 200 gpm for approximately 50 min. This release rate is approximately 2% to 4% of the valve capacity and was probably not noticed by the plant staff because its noise and steam discharge were masked by the noise and steam from the nearby A steam generator atmospheric PORV. The Task Force's mass balance (attempting to account for all the reactor coolant system and secondary water throughout the event) is discussed in Section 3.6. The mass balance also tends to support the position that the safety valve failed to properly reseat for 50 min.

At 11:52 a.m., pressurizer level indication came back on scale. The estimated rate of leakage through the B steam generator safety valve and the continued plant cooldown would explain the return of the pressurizer level during the period when charging flow exceeded letdown. The maximum rate of decrease of the indicated pressurizer level agreed well with that predicted by calculations. Normal letdown had been restored at about 12:02 p.m. At about 12:12 p.m., one safety injection pump was restarted, apparently for the purpose of arresting the decrease in pressurizer level caused by the continuing leak into the B steam generator. The safety injection pump was then operated intermittently to control pressurizer level throughout the remainder of this phase.

3.2.9 Phase 9--Leak Termination and Cooldown
(Period from 12:27 p.m., 1/25/82 to 10:45 a.m., 1/26/82)

At about 12:25 p.m., the B steam generator safety valve appears to have seated. The steam generator indicated pressure then increased to a value slightly above the reactor coolant system pressure, and the reactor coolant system leak was terminated. At about 12:35 p.m., the safety injection pump was stopped; it was no longer needed to control pressurizer level.

The break flow was controlled by attempting to maintain the reactor coolant system pressure at about 25 psi below the B steam generator pressure during the reactor coolant system cooldown and depressurization. The B steam generator was, therefore, leaking water back into the reactor coolant system during this phase of the event. The B steam generator cooldown was being controlled by the heat transfer from it to the reactor coolant system.

After 12:27 p.m., the cooldown proceeded at a very slow rate, which allowed time for the reactor coolant system to be degassed before using the residual heat removal system (the low-temperature and low-pressure decay heat removal system). During this phase of the event, the B steam generator water level indication came back on scale on the narrow-range instrument at approximately 6:40 p.m., January 25, 1982.

When the Task Force estimated the break flow for an indicated 25-psi differential pressure, the calculated flow was found to be about four times larger than that expected based on the rate of level observed decrease in the B steam generator. The rate of change of the B steam generator wide-range water level indication implies a 37-gpm leak rate. The rate of change of the B steam generator narrow-range level indication implies a 32-gpm leak rate. The return from being offscale after 7 hours of leakage back into the reactor coolant system implies approximately a 39-gpm leak rate. Considering the limited data available, these values are considered to be in good agreement.

Since the B steam generator pressure sensor is at an elevation approximately 60 ft above the elevation of the pressure sensor in the reactor coolant loop and the steam generator was flooded with water, the actual pressure differential at the break would have been 28 psi greater than indicated. Therefore, an indicated steam generator pressure 25 psi greater than reactor coolant system pressure would mean a break differential pressure of 53 psi, which would have supported a much larger leak rate of approximately 150 gpm. For the leak rate to have averaged 36 gpm, the pressure difference must have been less than 3 psi. After reviewing the reactor coolant loop pressure measurements and all three B steam generator pressure measurements for the cooldown phase, particularly the pressure oscillations occurring between 8:00 p.m., and 11:00 p.m., January 25 (see Figure 3.9), the Task Force finds that the reactor coolant loop pressure measurement (P420) was in error (too low) by approximately 50 psi. This error was recognized by the plant staff sometime during this phase and may have existed throughout the entire event, since a similar bias can be seen in the data at 9:26 a.m. An error of this magnitude is not surprising in a pressure instrument with a range of 0 to 3000 psig. (Note: A normal pressure instrument accuracy specification is 1% of full scale, which for this instrument is 30 psi.)

The fact that the B steam generator pressure did not decrease to the saturation pressure corresponding to the temperature of the water being pumped through the steam generator tubes, indicates that thermal stratification existed in the generator and its attached main steam line. Thermal stratification is to be expected in a steam system which has been overfilled, particularly for a design like that of Ginna in which upper internals impede water volume communication and the steam line slopes downward toward the turbine and allows hot water to be trapped. This information, together with the information on the leak rate, indicates that the primary reasons for the slow depressurization of the B steam generator were (1) the extremely small pressure differential between the reactor coolant system and the B steam generator and (2) the thermal stratification of the water in the steam generator, which prevented complete cooling.

After 12:25 p.m., January 25, the flow through the ruptured tube was from the B steam generator into the reactor coolant system. Under this condition there is concern for potential dilution of the boric acid in the reactor coolant system. The boron concentrations in the B steam generator and the reactor coolant system were checked, by sampling, before the cooldown and depressurization began and at approximately half-hour intervals thereafter. The B steam generator samples indicated 1100-ppm boron. Because of the amount of boric acid injected into the reactor coolant system from the boric acid storage tanks and refueling water storage tank, there was never any potential for an inadvertent criticality (the boron concentration needed to maintain the required shutdown margin was approximately 700 ppm) because of boron dilution during this event.

At approximately 6:40 p.m., the B steam generator narrow-range water level indication was on-scale, and auxiliary feedwater was supplied for the first time since 9:32 a.m. This was done to assist in the cooldown of the steam generator and helped to degas it.

[redacted]

When the B steam generator was depressurized, a gas mixture was found that included hydrogen and gaseous fission products, such as xenon, both of which are normally found in the reactor coolant system. The hydrogen is intentionally added to control the oxygen content of the reactor coolant system. Some fission product gases are always present in pressurized water reactor systems. The presence of these noncondensible gases may have also contributed to the slow depressurization of the steam generator.

The residual heat removal system was placed in service at about 7:00 a.m. on January 26, 1982. The plant staff chose to maintain system conditions without substantial reactor coolant system cooldown while the reactor coolant system was cleaned and degassed using the chemical and volume control system (CVCS) at a letdown rate of 50 to 60 gpm.

3.3 System Description

Important system parameters are listed in Table 3.2 (see Section 3.2.1). The system descriptions are discussed in the following sections.

3.3.1 Reactor Coolant System

The reactor coolant system consists of those components through which the reactor coolant flows. These include the reactor vessel, two steam generators, two reactor coolant pumps, the pressurizer, and the piping connecting these components. The reactor coolant system functions to contain and circulate the water which cools the reactor core by transferring heat to the steam generators.

Figure 3.10 presents a simplified view of the system in the Ginna plant. The relationships among the reactor coolant system, secondary system, and safety and auxiliary systems can be seen in the figure. A reactor coolant pump is located in each of the two heat transfer loops of the system, which circulates coolant. The pump has a three-stage controlled leakage seal assembly to limit reactor coolant leakage along the pump shaft. Seal injection is provided by the high-pressure water flow from the charging pumps, which are part of the

CVCS. Part of the seal injection flow enters the reactor coolant system and the remainder is returned to the CVCS. The pump may be operated without seal injection flow provided component cooling water is available and the seal leakage is less than 5 gpm.

A vertical, inverted U-tube steam generator is employed in each of the reactor coolant loops. The steam generator is a Westinghouse series 44 design (shown in Figure 3.11), which is the series of steam generators employed at Point Beach Unit 1 and several other Westinghouse-designed plants. Reactor coolant enters the inlet nozzle from the hot leg of the reactor coolant system, flows through the U-tubes, where heat is transferred to the secondary system, and exits the steam generator to the cold leg of the reactor coolant system.

Feedwater to the secondary side of the steam generator enters above the top of the U-tubes through a sparger. The water flows downward through the annulus between the U-tube wrapper and the outer shell of the steam generator and then upward through the U-tube bundle, where a portion of the feedwater is converted to steam. The moisture entrained in the steam is removed and spilled over into the annulus. (The steam generator is further discussed in Section 7.3.2 of this report.)

Figure 3.12 presents a simplified piping and instrumentation diagram of the reactor coolant system. This figure illustrates the arrangement of the reactor coolant system components, the location of the connections with other systems, and the location of various instruments. Figure 3.13 provides a view of the instrument locations relative to the various components and the relative sizes and elevations of the components.

The reactor coolant loop temperatures are derived by use of resistance temperature detectors, which in turn are used to compute T_{AVE} and the loop ΔT, and are used by the saturation monitor to compute subcooling. Although the hot-leg temperatures are not recorded or indicated, except as requested of the computer, all other loop resistance temperature detector outputs are indicated in the control room.

[redacted]

Subcooling is indicated in each loop using the pressurizer pressure and B hot-leg temperature for one meter and the wide-range loop pressure (PT-420) and A hot-leg temperature for the other meter. A second measure of reactor coolant system subcooling is calculated by the process computer using wide-range loop pressure (PT-420) in the hot leg of loop A and the average of a preselected group of five of the 39 core exit thermocouples. The wide-range pressure is derived from a single instrument which displays the pressure trend on a strip chart in the control room, but no other meter is provided for the pressure range 750 to 1700 psig.

Figure 3.14 shows the recorders used to monitor the reactor coolant system cold-leg temperature and pressure, key parameters during the Ginna event. The actual pressure recorder strip chart is reproduced in Figure 3.15. This was the only pressure data available to the operators during the process computer failure, since the pressure was below the lower limit of indication on the pressurizer pressure indicator (1700 psig). This pressure instrument is not safety related but was used extensively to follow the event. The trend recorder was indicating approximately 30 psi higher than the process computer values.

During normal operation, the pressurizer's function is to control the reactor coolant system pressure by utilizing spray (pressure reduction), heaters (pressure increase), and pressurizer relief (PORV) and safety valves (pressure reduction). Pressurizer spray can be obtained from either loop when the reactor coolant pumps are operating or from the CVCS system using auxiliary spray. The PORVs prevent opening of the safety valves for mild pressure transients. The PORVs can be manually opened from the control room. The motor-operated block valve upstream of the PORV provides a means of isolating a stuck-open or leaking PORV. The positions of the pressurizer PORVs and their block valves are indicated by a discrete set of lights for each valve. The signals for these indications are derived from limit switches that are actuated by the stem of the valves. The PORV positions are also transmitted to the computer. The PORVs are not monitored by sonic devices, but the common PORV tailpipe leading to the pressurizer relief tank is equipped with a temperature transmitter detector.

[redacted]

The pressurizer pressure instruments consist of four pressure transmitters which generate signals for reactor protection (i.e., reactor trip), pressure control, safety injection, and anticipatory alarms and indication. These instruments actuate a reactor trip and a safety injection on low pressurizer pressure. The reactor low-pressure trip setpoint is rate-compensated so that a trip would be initiated before the pressure decreases to the nominal setpoint (i.e., the faster the pressure decreases, the higher the actual system pressure would be when pressure trip is initiated).

The pressurizer pressure instrumentation has a lower limit of indication of 1700 psig and is the only pressure instrument on the reactor coolant system that is environmentally qualified. Consequently, the reactor coolant pump trip criterion at Ginna for emergency procedures was chosen to coincide with a pressurizer pressure of 1715 psig. Below 1700 psig, the wide-range pressure instrument in the A loop was used for operator control purposes.

The PORVs and safety valves relieved to the pressurizer relief tank. A typical tank is shown in Figure 3.16. The pressurizer relief tank also collects the steam and water from the relief valves on the reactor coolant pump seal return and letdown lines. The instrumentation is shown on Figures 3.12 and 3.16, including pressure, temperature and level instruments. The rupture disc fails when the tank pressure exceeds 100 psig, and the fluid lost from the tank is collected in the A containment sump.

The relevant instruments for the reactor vessel are the core exit thermocouples, consisting of 39 chromel-alumel units that are located above the upper core plate for monitoring core exit temperatures, and three similar sensors located above the upper support plate for monitoring upper head fluid temperature.

During normal operation a part of the cold-leg flow is directed to the upper head for cooling the region. As a result, the upper head fluid temperatures are maintained about 10°F less than the hot-leg temperatures at full power. An upper head vent was installed, but procedures for its use have not been completed. A vessel level indicator does not exist in the Ginna plant.

3.3.2 Secondary System Design

The main steam system is shown in Figure 3.17. The main steam system supplies steam to the turbine generator, the turbine-driven auxiliary feedwater pump, the gland steam system, the steam dump system, the steam reheaters, and the air ejector.

Steam from each steam generator flows to the turbine via the main steam line through a flow restrictor, a main steam line isolation valve (MSIV), and a check valve to the main steam header. Steam is directed to the various steam loads from the main header. Each main steam line has one PORV, four safety valves, and one steam supply valve to the turbine-driven auxiliary feedwater pump; all are located upstream of the MSIV.

The exhaust from the main turbines is condensed in the condenser and collected in the hotwell. The condenser is a large heat exchanger, which operates at a vacuum. Cooling water from the circulating water system flows through tubes, and the condensing steam flows over them. Lake Ontario is the source of the circulating water.

The air ejectors help maintain a vacuum by scavenging noncondensible gases from the condenser. Steam from the main steam header provides the motive power for removing the gases from the condenser. Steam from the air ejector is condensed by a heat exchanger cooled by the condensate system. The noncondensible gases pass through a radiation monitor and exhaust to the atmosphere. Condensate flow must be provided in order for the air ejectors to be operable.

The steam supply for the turbine-driven auxiliary feedwater pump flows from each main steam line upstream of the main steam isolation valve through a motor-operated valve. The signals that open the valves are listed in Table 3.2.

The steam dump system provides a method for creating an artificial steam load to prevent reactor trip during turbine load reductions and to prevent atmospheric steam releases, thereby conserving condensate inventory. The piping for the steam dump system is from the main steam header downstream of the MSIV and the system exhausts to the main condenser through eight dump valves. The control system for these valves has two separate control modes: steam pressure and reactor coolant average temperature (T_{AVE}). The pressure mode is used during startup to 15% power. The operator selects the T_{AVE} mode above 15% power. The control system modulates the dump valves according to the mode control selected. The rated capacity of the steam dump system is 40% of the plant design steam flow.

In the event that the steam dump system is inoperable, the steam generator PORV and four safety valves located on each main steam line can dump steam to atmosphere to control steam line pressure. The relief valve will relieve 10% of rated steam flow; it is controlled automatically or manually by the control room operators. The setpoint for the atmospheric PORV is normally 1050 psig but can be reduced by operators in the control room. The steam generator safety valves are capable of relieving 100% of maximum calculated steam flow. The first safety valve is set at 1085 psig (system design pressure) and the others are each set at a pressure of 1140 psig. Only the relief valve has an isolation valve which can be closed in the event the valve fails open.

The feedwater and condensate systems are shown in Figures 3.18 and 3.19. The feedwater and condensate systems form a closed cooling water system with full flow polishing (clean up) capability. These systems are composed of the condenser, three 50% condensate pumps, three 50% condensate booster pumps, four demineralizers (three in normal operation), hydrogen coolers, an air ejector condenser, a turbine gland steam condenser, low-pressure feedwater heaters, two 50% motor-driven feedwater pumps, and two high-pressure feedwater heaters.

The auxiliary feedwater system is a safety-related system which supplies feedwater to the steam generators for removal of heat from the reactor coolant system in the event the main feedwater system is inoperable. The system is composed of one turbine-driven and two motor-driven auxiliary feedwater pumps which take suction from the two condensate storage tanks and deliver to the steam generator feedwater line through separate nozzles downstream of the feedwater isolation valve. The turbine-driven auxiliary feedwater pump supplies 200 gpm to each steam generator. Each motor-driven pump normally supplies only one steam generator at a rate of 200 gpm. A redundant standby auxiliary feedwater system was available but was not utilized during the event.

The condensate pumps take suction from the condenser hot well and pump the condensate through the condensate demineralizers to the condensate booster pumps. The booster pumps provide the required net positive suction head for the main feedwater pumps. They pump the water through the air ejector condenser, gland steam condenser, hydrogen coolers, and low-pressure feedwater heaters to the main feedwater pumps. Both feed pumps discharge through high-pressure feedwater heaters to the steam generators. Each steam generator feedwater line has a feedwater-regulating valve, a feedwater-isolation valve, and a feedwater-bypass valve.

A relevant design feature of the condensate system is that upon a high level in the condenser hotwell, condensate is automatically rejected to the two condensate storage tanks. A steam generator tube rupture event would add water to the secondary system which would collect in the condenser hotwell. Consequently, the condensate storage tanks can become contaminated during this process. Since the auxiliary feedwater pumps take suction from these tanks, subsequent atmospheric radiological releases can result during steam line safety or relief valve operation.

The secondary system instruments include those which monitor steam generator level, feedwater flow, steam flow, and steam generator pressure. There are also instruments for monitoring the positions of the steam generator PORVs, the steam generator safety valves, the turbine-driven auxiliary feedwater pump steam supply valves, steam dump valves, and condenser vacuum. A chart recorder is dedicated to each steam generator to monitor the lifting of the atmospheric PORVs, the safety valves, and the opening of the respective steam supply valve to the turbine-driven auxiliary feedwater pump. These recorders automatically start on a 30 mr/hr reading in the associated steam line. The monitoring of radiation from the steam jet-air ejector and steam generator blowdown lines are addressed in Section 5. Steam generator blowdown is isolated automatically on a high radiation alarm, low-low steam generator level, trips of both main feedwater pumps, operation of a motor-driven auxiliary feedwater pump, and on containment isolation.

The steam generator level instrumentation system includes eight level transmitters (three narrow-range and one wide-range transmitter per steam generator). The narrow-range transmitters are hot calibrated; the wide-range are cold calibrated.

The feedwater and steam flow instruments each include two flow transmitters per loop. The feedwater flow, steam flow, and level signals are fed into a three-element controller which controls steam generator level. Outputs from the three-element controller are produced by the level deviation or mismatch of steam flow and feed flow. A level control deviation alarm is actuated in the control room whenever the actual level deviates ±7% from the programmed level signal. A difference between feed flow and steam flow of 8×10^5 lb/hr produces an alarm.

3.3.3 Safety Injection System

The safety injection system is designed to supply water to the reactor coolant system during accident conditions. The water provides cooling of the fuel by ensuring that the core is covered with water. It provides shutdown margin by ensuring that sufficient boric acid is added to the reactor coolant system to prevent or suppress any inadvertent criticality. The safety injection system consists of high-pressure safety injection pumps, low-pressure pumps (residual heat removal pumps), safety injection accumulators, the boric acid tanks, and the refueling water storage tank. The high-pressure safety injection components and their connections to the reactor coolant system are shown in Figure 3.20. The low-pressure safety injection components and the accumulators were not utilized during the safety injection phase. The actuation signals for safety injection are listed in Table 3.2.

After safety injection has been started, all the automatic actions that are caused by this actuation (e.g., containment isolation) remain in effect until the system has been reset. After the system has been reset, systems that tripped or were blocked, such as the charging pumps and containment isolation, may be manually controlled on an individual component basis. Likewise, systems that started automatically, such as the safety injection pumps, may be tripped manually. The prerequisites for resetting the safety injection system include the timing out of a 60-second timer to ensure sufficient time for the sequencing of safety injection-related loads onto the diesel generators. In addition, Ginna procedural requirements (such as verifying that safety injection suction has been transferred from the boric acid storage tank to the refueling water storage tank) must be completed before resetting the safety injection system.

In the event that safety injection was reset before the transfer had been completed, the boric acid storage tanks would empty and the automatic transfer would not be completed. Manual action would then be required to prevent safety injection pump cavitation and potential damage.

Safety injection flow, boric acid storage tank level, and refueling water storage tank level are indicated in the control room. Safety injection flow is not recorded in a permanent record. The tank levels are printed hourly by the process computer.

The safety injection pump characteristics are shown in Figure 3.6. This curve was calculated based on preoperational test data and accounting for recirculation flow.

The residual heat removal system includes the low-pressure safety injection pumps. The system transfers heat from the reactor coolant system to the component cooling loop, of the auxiliary coolant system. After the steam generators have reduced the temperature and pressure in the reactor coolant system to 350°F and 400 psig, decay heat is normally removed by taking suction from the hot leg of the A loop to the two residual heat removal pumps, through the residual heat removal heat exchangers to the cold leg of the B loop.

3.3.4 Containment System

The containment system is a reinforced concrete shell structure that has a welded steel liner attached to the inside face of the concrete shell to ensure leak tightness. The containment structure completely encloses the reactor coolant system and certain related auxiliary components, such as the pressurizer relief tank. In addition, the containment system includes a sump (sump A) as shown in Figure 3.21, to accommodate leakage, such as that from the overflowing of the pressurizer relief tank, or condensation which may occur upon cooling the containment system with its air-recirculation coolers. The containment system also includes several types of penetrations, some of which are for equipment and personnel access, others for fluids (which may or may not be isolated upon a containment system isolation signal), and others for electrical and instrumentation purposes.

The level-sensing instruments associated with sump A include two redundant strain-gauge-type level transmitters calibrated to the range of 0 to 30 ft of water, each of which serves a vertical indicator located in the control room. The sump is approximately 5 x 5 x 5 ft.

In addition to the indicating instrumentation, sump A is also provided with instrumentation for starting and stopping its two pumps and for alarming at high sump levels. The actuating and alarm signals are provided by limit switches mounted on float switches.

The containment isolation system at Ginna is designed to ensure that fission products resulting from an accident are retained within the containment system. Thus, all potential leakage pathways (pipes, ducts, etc.) that penetrate the containment system and are not required to ameliorate the effects of the accident are isolated. The valves which receive a containment isolation signal are listed in Table 3.4. All valves receive their isolation signals simultaneously and are not divided into phases.

Table 3.4 Containment isolation

Valve No.*	System Isolated
AOV5392	Instrument air isolation valve
AOV371	Letdown isolation valve
MOV313	Seal water return
AOV846	Nitrogen
MOV813	Component cooling supply to reactor support cooling
AOV5738	A steam generator blowdown
AOV5737	B steam generator blowdown
AOV1721	Reactor coolant drain tank
LCV1003A	Reactor coolant drain tank
AOV1786	Reactor coolant drain tank vent header
DV1723	Containment sump
VSP1A	Sump pump
VSP1B	Sump pump
AOV1789	Reactor coolant drain tank gas
AOV539	Pressurizer relief tank gas
AOV959	Residual heat removal sump
AOV966A	Pressurizer steam sample
AOV951	Pressurizer steam sample
AOV966B	Pressurizer liquid sample
AOV953	Pressurizer liquid sample
AOV966C	B hot-leg sample
AOV955	B hot-leg sample
AOV5735	A steam generator sample
AOV5736	B steam generator sample
AOV508	Reactor makeup water
AOV1597	Radiation monitor
AOV1598	Radiation monitor
MOV7443	Leak test valve
MOV7444	Leak test valve
MOV7445	Leak test valve
AOV7971	Depressurization valve
AOV7970	Depressurization valve
AOV8418	Demineralized water
MOV814	Component cooling return from reactor support cooling
LCV1003B	Reactor coolant drain tank
AOV1787	Reactor coolant drain tank vent header
DV1728	Containment sump
V1600	Reactor coolant drain tank gas
	Hydrogen recombiner
	Purge supply fan 1A and 1B tripped
	Purge exhaust fan 1A and 1B tripped
	Purge supply valves inside and outside containment
	Purge exhaust valves inside and outside containment

* These valves operate to isolate the system upon a containment isolation signal.

3.3.5 Chemical and Volume Control System

The chemical and volume control system (CVCS) controls the chemistry and volume of the reactor coolant system (RCS). Water with the desired content of boric acid and/or other chemicals is added to the reactor coolant system by the charging pumps. The three positive-displacement charging pumps (60-gpm capacity each) take suction from the volume control tank and pump the water into the reactor coolant system. The CVCS flow normally enters the reactor coolant system both through cold leg B and through the reactor coolant pump seals. Figure 3.22 shows the arrangement of the components of the CVCS. Table 3.2 provides important system characteristics. The charging pumps are not part of the safety injection system and are tripped on a safety injection signal, regardless of whether offsite power is available. Tripping the charging pumps removes an additional source of makeup water to the reactor coolant system, removes a filtered water supply to the reactor coolant pump seals, and removes the source of water for auxiliary pressurizer spray.

Figure 3.23 shows the valve arrangements for the letdown system as it penetrates the containment. The letdown line is isolated outside the containment by air-operated valve AOV371, which receives an automatic containment isolation signal. Inside containment, the line can be isolated by the use of either the regenerative heat exchanger inlet valve LCV427 or the letdown orifice isolation valves LCV200A, LCV200B, or LCV202. The latter four valves are also air operated. During normal operation, AOV371, LCV427, and one orifice isolation valve are open. Valve LCV427 automatically closes on low pressurizer level, and the orifice isolation valves are interlocked with valve LCV427 controls such that they will also automatically close if valve LCV427 receives an automatic closure signal. In addition, on loss of instrument air, valve LCV427 fails open and valves LCV200A, 200B, and 202 fail closed. The letdown orifices reduce the service pressure of the line downstream of them during normal letdown operations; consequently, the design pressure of this piping is less than the normal reactor coolant system pressure. To protect against excessive pressure in the downstream piping, a relief valve is provided. At the time of the event, neither valve LCV427 nor the orifice isolation valves were designed to receive automatic containment isolation signals.

Figure 3.24 shows the valve arrangement for the reactor coolant pump seal return line as it penetrates containment. As is shown in the figure, seal return flow from each reactor coolant pump joins together in a common pipe, which then penetrates containment. This line is automatically isolated on containment isolation by the closing of motor-operated valve MOV313. During normal operation, seal injection is supplied to the reactor coolant pumps and returned to the volume control tank through valve MOV313. Upon safety injection actuation, seal injection flow is secured because the charging pumps trip and valve MOV313 automatically shuts on containment isolation. Reactor coolant system leakage through the reactor coolant pump seals then pressurizes the seal return line up to valve MOV313. The seal return relief valve (314) will lift as pressure in the line increases. It can thus be seen that, at Ginna, seal return relief valve lifts during containment isolation events are unavoidable unless piping modifications which would negate the need for relief protection are made.

3.3.6 Computer System

The computer system, a Westinghouse PRODAC 250, is a dedicated real-time system consisting of a central processing unit with parametric inputs from the reactor coolant system, the secondary system, and auxiliary service systems throughout the plant. These inputs are stored as discrete, addressable data points which are used to perform specific computations (e.g., compute subcooling margin), generate alarms, indicate digital and analog information, and to provide pre-trip and post-trip data. The computer was designed to read and record information important to the normal steady-state operation of the plant. The computer system design is not well suited to post-accident evaluation requirements since it does not record parameters such as safety-injection flow, safety system tank levels, and safety system valve position. This limitation has made post-accident analysis difficult and has introduced uncertainties in Task Force estimates of break flow and atmospheric release. The peripheral devices served by the plant computer include:

(1) Alarm typewriter--The alarm typewriter prints most alarms, but not all, and not necessarily in sequence when several occur in close order. The alarm is printed in bold type, and cleared alarm and other information

appear in medium type. Depending on the number of alarms and other information to be printed, the output may be printed minutes after the alarm occurred.

(2) Log typewriter--The log typewriter prints selected plant parameters chosen by the operators. Output is slow, and capability for real time assessment is limited.

(3) Pre-trip/post-trip review printer--This device provided pre-trip and post-trip data from 2 min prior to the trip to 2 min after the trip in 8-sec increments.

(4) TI-7000 teletype terminal--This terminal is located in the Technical Support Center. Combinations of system parameters can be displayed upon demand on a time basis. This device provided much of the data necessary for post-event analyses.

The process computer is located in the Turbine Building below the control room.

3.4 Task Force Estimate of the Leak Rate

The Task Force has reviewed the hourly log readings of the radiation monitors on the steam jet air ejector and on the steam generator blowdown system. These readings were consistently low and showed no increasing trend up to 9:00 a.m. (which was the last hourly reading before the tube rupture). This indicates that it is unlikely that the tube rupture developed from a small growing leak.

The detailed plant computer data readings begin 2 min before the reactor trip. By extrapolating the data trends on pressurizer level and pressurizer pressure back to their steady-state values, the time of the tube rupture was established as 9:25:25 a.m.

Between 9:25:25 a.m. and 9:26:27 a.m., the pressurizer level dropped from 47% to 30%. This decrease corresponded to a leak rate of 750 gpm, assuming a charging flow of 60 gpm and a letdown flow of 40 gpm.

Between 9:26:27 a.m. and 9:27:13 a.m., the leak rate was balanced by a combination of charging pump flow and thermal expansion of the water in the reactor coolant system. The expansion occurred when the turbine load reduction began at 9:26:27 a.m. This implies that the leak rate was approximately equal to 760 gpm (i.e., 180-gpm charging flow plus 620 gpm, which is equivalent to the heatup rate minus 40-gpm letdown flow).

After 9:27:13 a.m., the pressurizer level began to decrease again at a rate greater than the initial rate of decrease. This is to be expected, since the reactor coolant system temperature began to decrease at this time. The estimated leak rate associated with this period is 740 gpm, based on a cooldown rate corresponding to 600 gpm, a charging flow of 180 gpm, a letdown flow of 40 gpm, and a rate of decrease in pressurizer level corresponding to 1200 gpm.

When the pressurizer emptied shortly after 9:28 a.m., the reactor coolant system pressure dropped sharply and the leak rate also decreased. With the pressurizer level measurement offscale, the information on leak rate had to be based on fluid flow models and indirect indications.

For the initial period of the event, a homogeneous equilibrium flow model was also used to estimate the critical flow through the tube rupture. Assuming that the flow was limited by the minimum flow area near the break (i.e., twice the flow area of a tube), the homogeneous equilibrium flow model predicted a flow of about 700 gpm at 2100 psig and 600°F. The flow from the hot leg side of the ruptured tube was calculated, assuming reactor coolant system pressure at the break. The flow from the cold leg side was based on the calculated pressure at the break, including the pressure drop through the steam generator tubing. The model's predicted break flow probably differs from the value indicated by the pressurizer level changes (~750 gpm) because of the complex geometry of the break and because of uncertainties within the model itself.

As the reactor coolant system pressure and temperature decreased, the break flow was no longer limited by steam formation at the break. After approximately 9:40 a.m., the coolant was at a temperature equal to or below the saturation temperature in the B steam generator.

[redacted]

For the remainder of the event the break flow was estimated using an orifice flow equation in which the ruptured tube was modelled as two orifices with orifice coefficients equivalent to coefficients for a sharp-edge entrance, a sharp-edge exit, a length of pipe (2 ft in one case and 80 ft in the other), and a 90° bend (to simulate the effect of the fluid turning to exit the break). The estimated total loss coefficients were therefore 2.6 for the hot-leg side of the tube and 21 for the cold-leg side. The estimated break flow was therefore:

$$\begin{aligned} W\ (\mathrm{lb/sec}) &= 96.3 \times 0.0033 \times (\Delta P \times \mathrm{density}/2.6)^{\frac{1}{2}} \\ &\quad + 96.3 \times 0.0033 \times (\Delta P \times \mathrm{density}/21)^{\frac{1}{2}} \end{aligned}$$

The results obtained from this equation are presented in Figures 3.5 and 3.7.

The break-flow estimate was checked in the following ways. First, the total calculated flow into the steam generator of 47,000 gal was compared with the total estimated break flow from an accounting of the water entering and leaving the reactor coolant system. This accounting is discussed in Section 3.6. The agreement was within 10% and was better than the Task Force had expected. Second, the equilibrium between safety injection and charging flows and break flow for the period 10:17 a.m. to 10:38 a.m. was predicted well by the model. Figure 3.8 indicates that an equilibrium condition should be established at approximately 1410 psig, corresponding to an indicated pressure of 1385 psig. The data for the period indicate that the reactor coolant system pressure established an equilibrium value of approximately 1370 psig in good agreement with the prediction.

3.5 Temperature Distribution and Pressurized Thermal Shock Potential of Reactor Coolant System

During normal full-power operation both reactor coolant pumps are in operation. They each provide 80,000 gpm, and this flow rate results in a hot-leg to cold-leg temperature difference of 56°F. The reactor vessel upper head receives some water from each cold leg and some water from the region directly above the reactor core (reactor vessel upper plenum). This water mixes to produce a temperature approximately 10°F below the core exit water temperature. The water in the pressurizer is maintained at approximately 650°F in order to keep the system pressurized to 2200 psig.

Following the load reduction and reactor trip at 9:28 a.m. on January 25, the hot-leg to cold-leg temperature difference reached a minimum value of approximately 2°F. When the reactor coolant pumps were tripped at 9:29 a.m., the water at the core exit began to heat up and the hot-leg to cold-leg temperature difference reached a maximum value of approximately 40°F in about 10 min, and then decreased. Fully developed natural-circulation flow resulted in flow rates of approximately 8,000 gpm in each loop and a hot-leg to cold-leg temperature of 10°F to 20°F. The temperature difference is somewhat difficult to quantify because of the sparsity of hot-leg temperature readings. After 9:40 a.m., when the B steam generator was isolated, the B cold-leg temperature dropped to 120°F below the A cold-leg temperature. When the PORV was opened at 10:07 a.m., another decrease in the B cold-leg temperature was observed. An explanation of this behavior and the implications relative to thermal shock to the reactor vessel is provided below.

The two important elements determining the temperature in the B cold leg are the direction and magnitude of the flow in the loop and the temperature and flow rate of the water being injected into the B cold leg.

The B loop cold-leg temperature sensor is approximately 18 in. from the safety injection and charging nozzles in the direction of the reactor coolant pump and approximately 10° above the horizontal center line of the loop pipe. The sensor protrudes 1 in. into the 27½-in.-ID pipe. The safety injection nozzle connects to the top of the pipe and the charging nozzle connects to the side of the pipe. The B loop cold-leg temperature sensor would indicate a temperature close to the B steam generator temperature while flow was in the normal forward direction (i.e., from the steam generator through the reactor coolant pump to the reactor vessel downcomer). If flow in the B loop cold leg were in the reverse direction, the sensor would indicate the temperature of a mixture of water from the reactor vessel downcomer and colder water from safety injection and charging flow.

The mixed mean temperatures were calculated with the following formula:

$$T\ (\text{B cold leg}) = \frac{[\text{Loop flow} \times T(\text{A cold leg})] + [(\text{SI} + \text{charging flow}) \times 90°\text{F}^*]}{\text{Loop flow} + (\text{SI} + \text{charging flow})}$$

An estimate of safety injection flow rates was available, since the reactor coolant system pressure and A-loop cold-leg temperatures were recorded and flow characteristics of the safety injection pumps were reasonably well known. Since the B steam generator was hotter than the remainder of the system, excluding the reactor vessel upper head, no natural circulation would be expected. However, there would be flow from the B-loop cold leg to the broken tube. When various flow rates up to the total calculated break flow value were assumed in the equation for the mixed mean temperature, trends similar to the measured trends were observed. For a reverse flow of 400 gpm, the calculated values matched the data quite well from 10:05 a.m. to 11:21 a.m., the period immediately prior to reactor coolant pump restart. The period between 9:40 a.m. and 10:05 a.m. may have been a transition period during which the cold-leg forward flow reversed to establish stable reverse flow and the temperature of the B-loop cold-leg piping decreased to a temperature in equilibrium with that of the water in the B-loop cold leg. Figure 3.25 shows the measured temperatures as well as the calculated temperature in the B steam generator cold leg. This indicates that forward flow due to natural circulation existed up until 9:40 a.m., and that reverse flow may have existed from 10:05 to 11:21 a.m. It is clear that the actual reverse flow rate would have been much lower than 400 gpm. The break flow during this period was estimated to be about 400 gpm and this limits the maximum possible flow from the downcomer toward the reactor coolant pump to less than 200 gpm, since charging and safety injection to the B loop would be about 200 gpm and there would be some flow toward the break in the B hot leg. Therefore, if significant reverse flow did exist, the mixing was not complete when the water flowed past the B-loop cold-leg sensor.

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* Task Force's estimated conditions, based on a tank temperature of 69°F plus pipe heat tracing, and pump heating of 21°F.

The Task Force has considered several possible alternative flow conditions in the B cold leg, including fully stratified flow, slug flow, and flow reversals at several times during the event. The Task Force has not identified any alternative conditions which fully explain the data and are consistent with the known properties of mixing fluids.

If reverse flow in the B cold leg existed, the implications would be as follows: (1) the cold safety injection water would flow toward the reactor coolant pump rather than toward the reactor vessel at all times after 9:40 a.m.; (2) there would be significant mixing between downcomer water and safety injection water near the safety injection nozzle location; and, (3) the reactor vessel would never experienced temperatures significantly below the indicated temperature of the A-loop cold leg.

3.6 System Mass Balance

The Task Force attempted to account for all of the water added to and lost from the reactor coolant system and B steam generator. The important elements in the mass balance and their values (from the beginning of the event up to 12:30 p.m. when the leak was terminated) are shown in Table 3.5.

The mass balance indicates that about 18,300 equivalent gallons of water (steam and water at 540°F) was relieved through the safety valve. Table 3.6 lists the steam generator safety valve openings as determined from the B steam generator pressure history. [Note: Task Force analysis of the B steam generator and reactor coolant system pressure responses suggested that the Code safety valve may have leaked after its first opening. This may explain the observed sequential decreasing opening and closing pressures of the Code safety valve]. The properties of the fluid flowing through the valve were estimated based on the calculated volume of water in the steam generator and attached main steam line. Based on the break flow calculation, approximately 7000 gal of water was relieved when the valve failed to reseat between 11:37 a.m. and 12:25 p.m.

Table 3.5 Mass balance for reactor coolant system and B steam generator between 9:25 a.m. and 12:30 p.m.

Item		Value, gal	Basis
1.	Water added to RCS (SI + charging flow)	47,900	Changes in RWST level and BAST, VCT, and MUT levels, verified by calculated SI and charging flows
2.	Volume addition for heating water added	6,000	Density change for heatup from 90°F to 380°F
3.	Volume loss due to RCS cooldown	10,700	RCS cooldown from 571°F to 380°F; PZR cooldown from 650°F to 550°F
4.	Volume loss due to PORV, openings, letdown, and seal relief	2,900	PRT and sump level changes (at 380°F)
5.	Net leak into S/G B at 380°F	40,300	Sum of 1+2-3-4 (299,300 lb)
6.	Initial steam volume available for filling (steam generator and steam line)	29,600	Best estimate of normal hot full-power volumes (this value is not well quantified)
7.	Feedwater addition - steam loss before isolation	2,000	3 min of motor-driven AFW at 200 gpm plus 17 min of turbine-driven AFW at 200 gpm; -50% decay heat removal and cooldown
8.	Net volume change due to S/G temperature change	0	
9.	Volume addition due to heat up of RCS leakage	5,600	Density change for 380 to 540°F
10.	Loss through safety valve (at 540°F)	18,300	Sum of 5-6+7+8+9 (117,000 lb)

Table 3.6 Steam generator safety valve openings, closings, and pressures, January 25

Time opened	Opening pressure, psig	Time closed	Closing pressure, psig	Flow
10:19 a.m.	1080	10:19 a.m.+	1020	Steam
10:28 a.m.	1060	10:28 a.m.+	990	Steam
10:38 a.m.	1050	10:41 a.m.	840	Two-phase
11:19 a.m.*	1030	Unknown	Unknown	Two-phase
11:37 a.m.	1030	12:25 p.m.	840	Water

* The process computer failed between 11:19 and 11:35 a.m. and, consequently, no good data were available.

3.7 Comparison of Steam Generator Tube Rupture Events

Steam generator tube rupture events occurred previously at Surry, Point Beach, and Prairie Island.** A tabular comparison of the events was performed to qualitatively characterize the system responses for different break sizes.

Differences in system design and operator actions significantly affect the system responses. Tables 3.7 and 3.8 compare the relevant sequences for the four steam generator tube rupture events.

** An evaluation of these events is reported in NUREG-0651, "Evaluation of Steam Generator Tube Rupture Events," March 1980.

Table 3.7 Operator response*

Item	Point Beach	Surry	Prairie Island	Ginna
First indication of SGT rupture	Air ejector high radiation alarm	Maximum charging flow alarm and L_p drop	Air ejector high radiation alarm	Air ejector high radiation alarm B SG level deviation alarm B SG feed flow/steam flow mismatch alarm
Affected SG	B	A	A	B
Sequence of operator actions (time from rupture, min)				
Started 2nd charging pump	2	5	9	1
Started 3rd charging pump	19	NA	9½	2½
Isolated reactor letdown	8	5	?	3
Initiated load reduction	30	7	6	1½ (manual)
Rate of load reduction, %/min	5	10	10	10
Type of scram	Manual	Manual	Automatic	Automatic
Time of scram	47	10	10	3
Pressure at time of scram, psig	?	1950	1900	1900
Low-pressure scram setpoint, psig	1865	1860	1900	1873
Type of SIS	None	Manual	Automatic	Automatic
Time of safety injection	NA	11	10	3
Pressure at time of safety injection, psig	NA	1800	1815	approximately 1723
Low-pressure SIS setpoint, psig	1715	1700	1815	1723
Peak pressure following safety injection	NA	2100	2000	1400
Time of peak pressure	NA	16	22	53
Method of terminating pressure rise	NA	Normal pressurizer spray and RCS cooldown	One pressurizer PORV manually operated	One pressurizer PORV manually operated
RCP trips	Manual; RCP B	Manual; RCP B	Manual; both RCPs	Manual; both RCPs
Time of RCP trip	66	19	12	4
RCP restarts	RCP B	None	RCP B	RCP A
Time of RCP restarts	100	NA	420	117
Time when MSIV shut	48	17	27	15
Time when stopping feeding affected SG	58	17	?	7
Stopped one SI pump	NA	15	32	72

*Table 13 from "Evaluation of Steam Generator Tube Rupture Events" (NUREG-0651), March 1980.

Table 3.8 Systems performance comparison

Parameter	Point Beach	Surry	Prairie Island	Ginna
Leak rate, peak, gpm	125	330	336	760
dP/dt, actual, psi/min	-	20	81	180
Time to scram, actual, min	47*	10*	10+	3+
Power at scram, %	25	70	90	70
Time from scram to safety injection, actual, sec	None	60*	approx. 5+	3
Minimum RCS subcooling, estimated, °F	-	45	32	0
Time to shut MSIV, min	48	17	27	15
Time to stop feed flow, min	58	17	?	7
Post-safety injection RCS repressurization rate, psi/min	-	43	43.8	3.2
Post-safety injection RCS peak pressure,** psig	-	2100	2000	1400
Time to pressure equalization across damaged SG, min	108	30	61	180
Normal spray:				
Flow, gal/min	300	575	400	approx. 300***
dP/dt, psi/min	88.5	128	118	approx. 90
Normal spray and one RCP tripped:				
Flow, gal/min	approx. 180	approx. 420	approx. 240	approx. 300**
dP/dt, psi/min	53.1	93.5	70.8	approx. 90
PORV				
Flow, lbm/h	179,000	179,000	179,000	179,000
dP/dt, psi/min	450	388	450	450

* Manual.

+ Automatic.

** Method of RCS pressure control: Point Beach and Surry use normal spray and RCS cooldown; Prairie Island uses intermittent pressurizer PORV operation and RCS cooldown; Ginna method described in Table 3.2.

*** Spray was not important parameter during Ginna event. Both loops have spray connection.

(Note: Table 11 from "Evaluation of Steam Generator Tube Rupture Events," NUREG-0651, March 1980.)

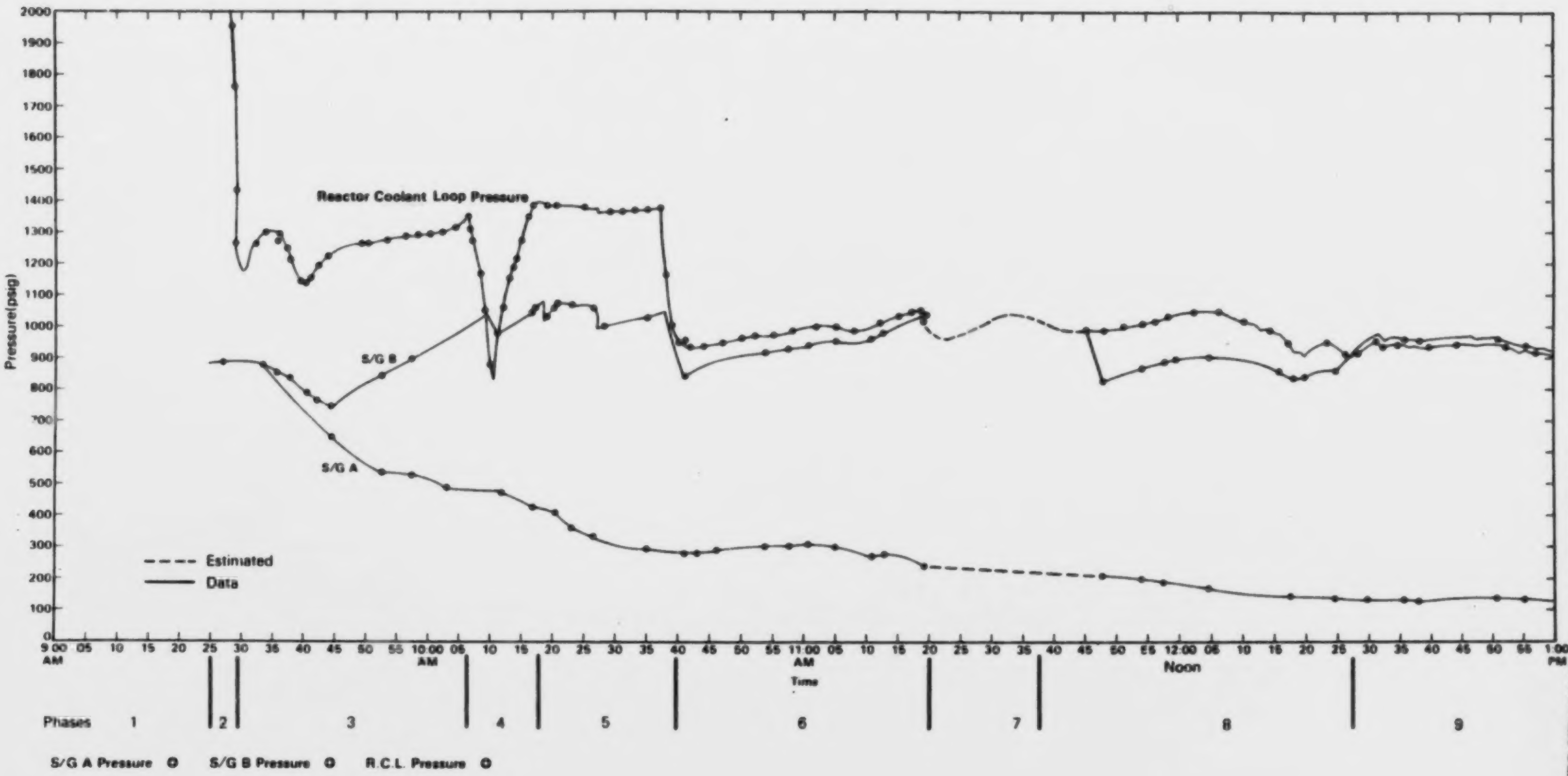

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Figure 3.1 Reactor coolant system and steam generator pressure response as a function of time, January 25, 1982

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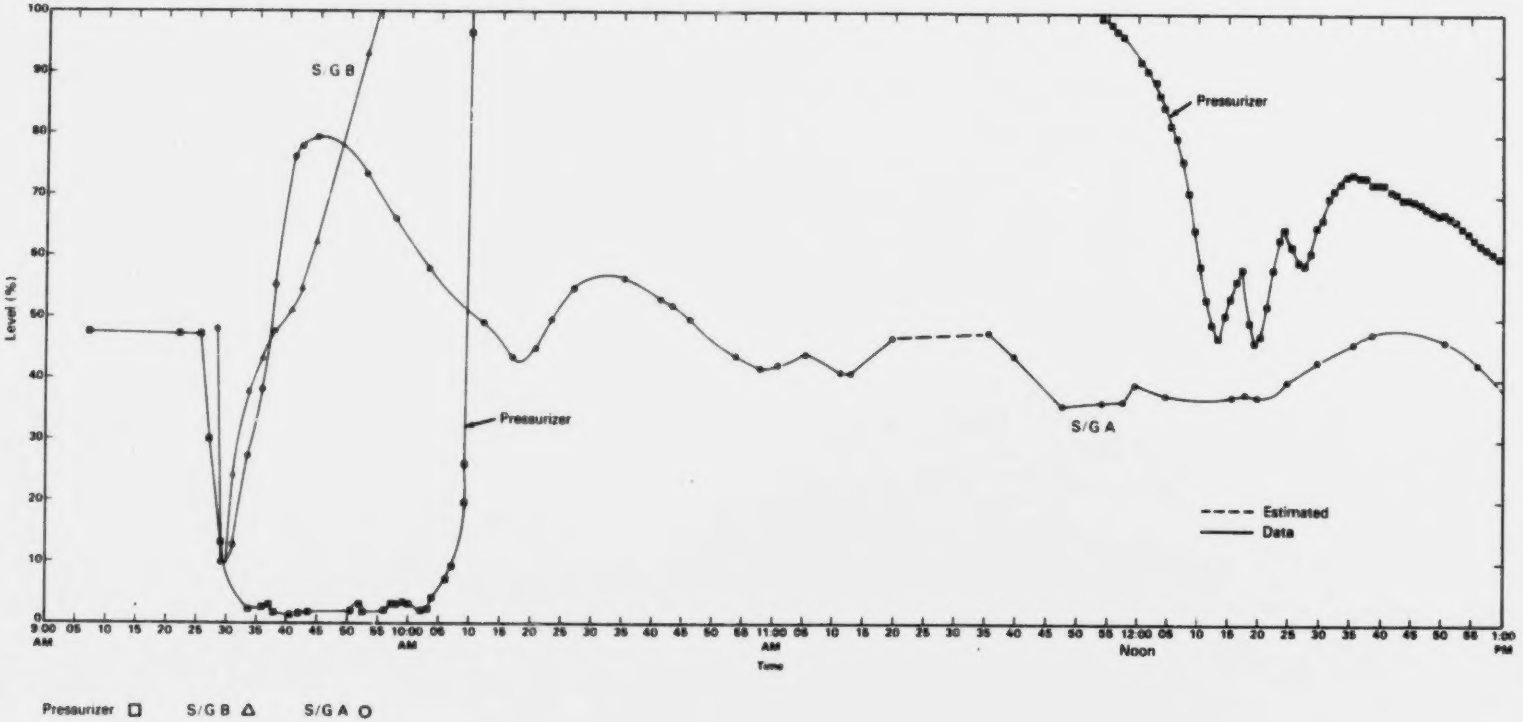

Figure 3.2 Pressurizer and steam generator level response, January 25, 1982

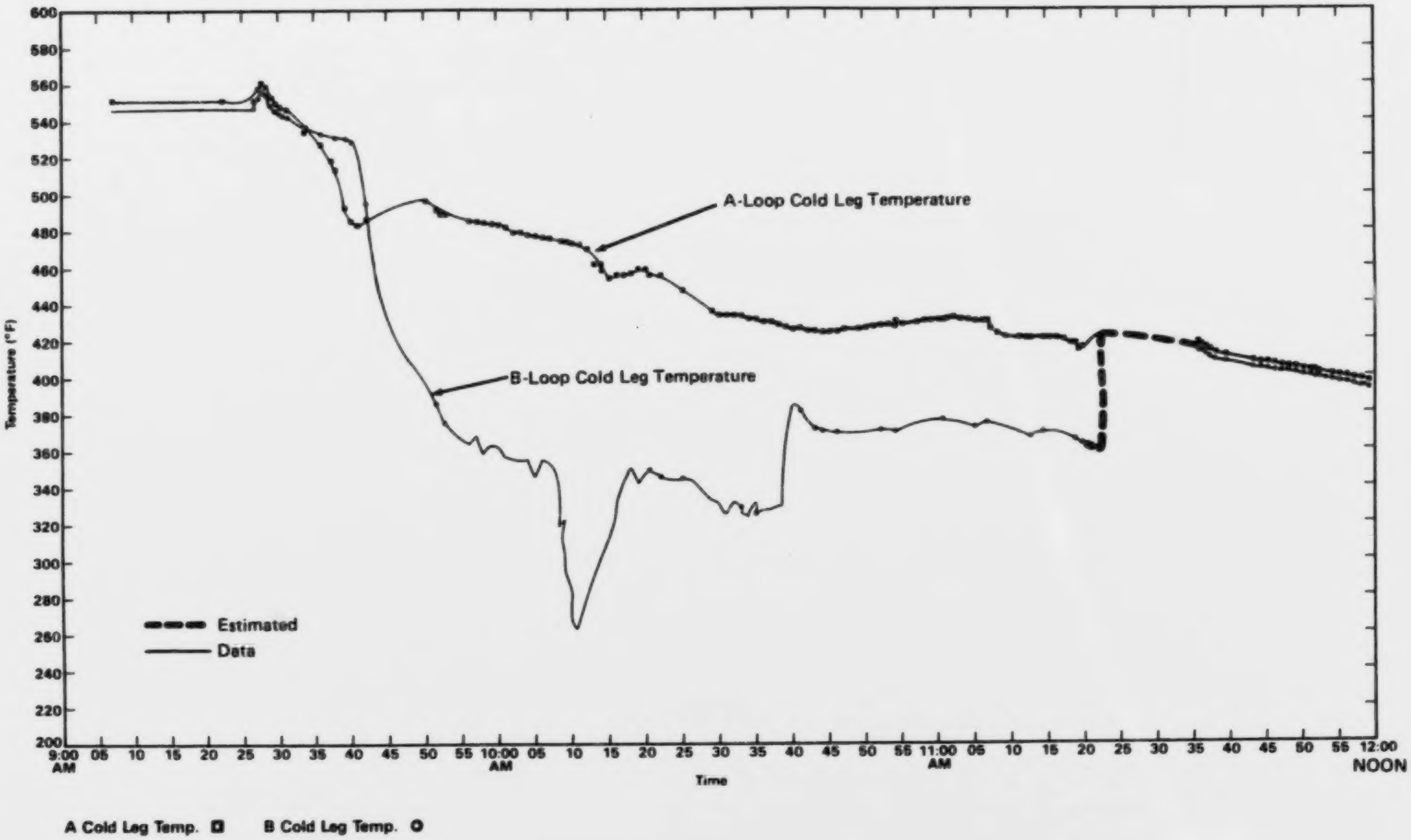

Figure 3.3 Reactor coolant loop cold-leg temperature as a function of time, January 25, 1982

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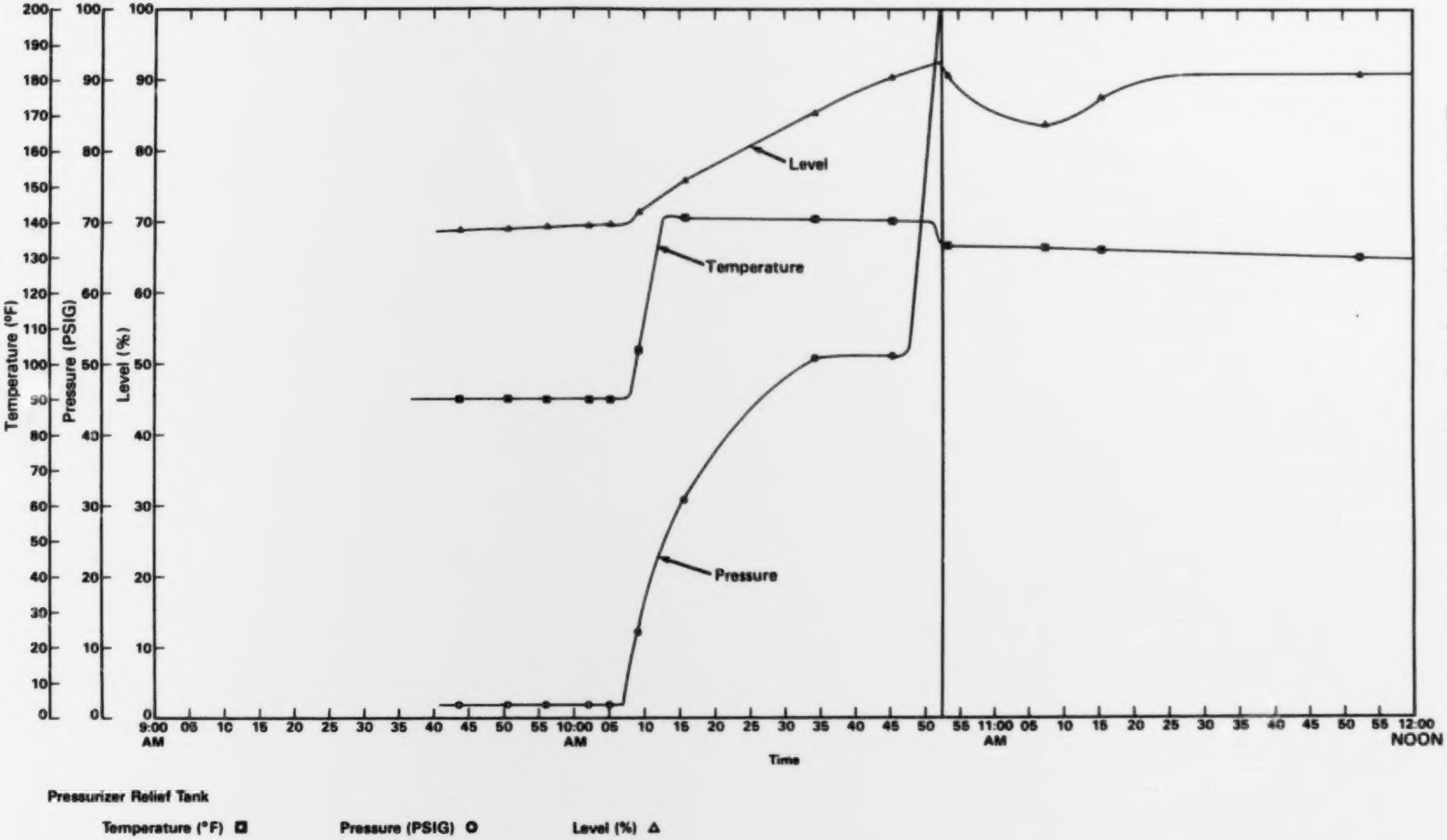

Figure 3.4 Pressurizer relief tank level, temperature, and pressure as a function of time, January 25, 1982

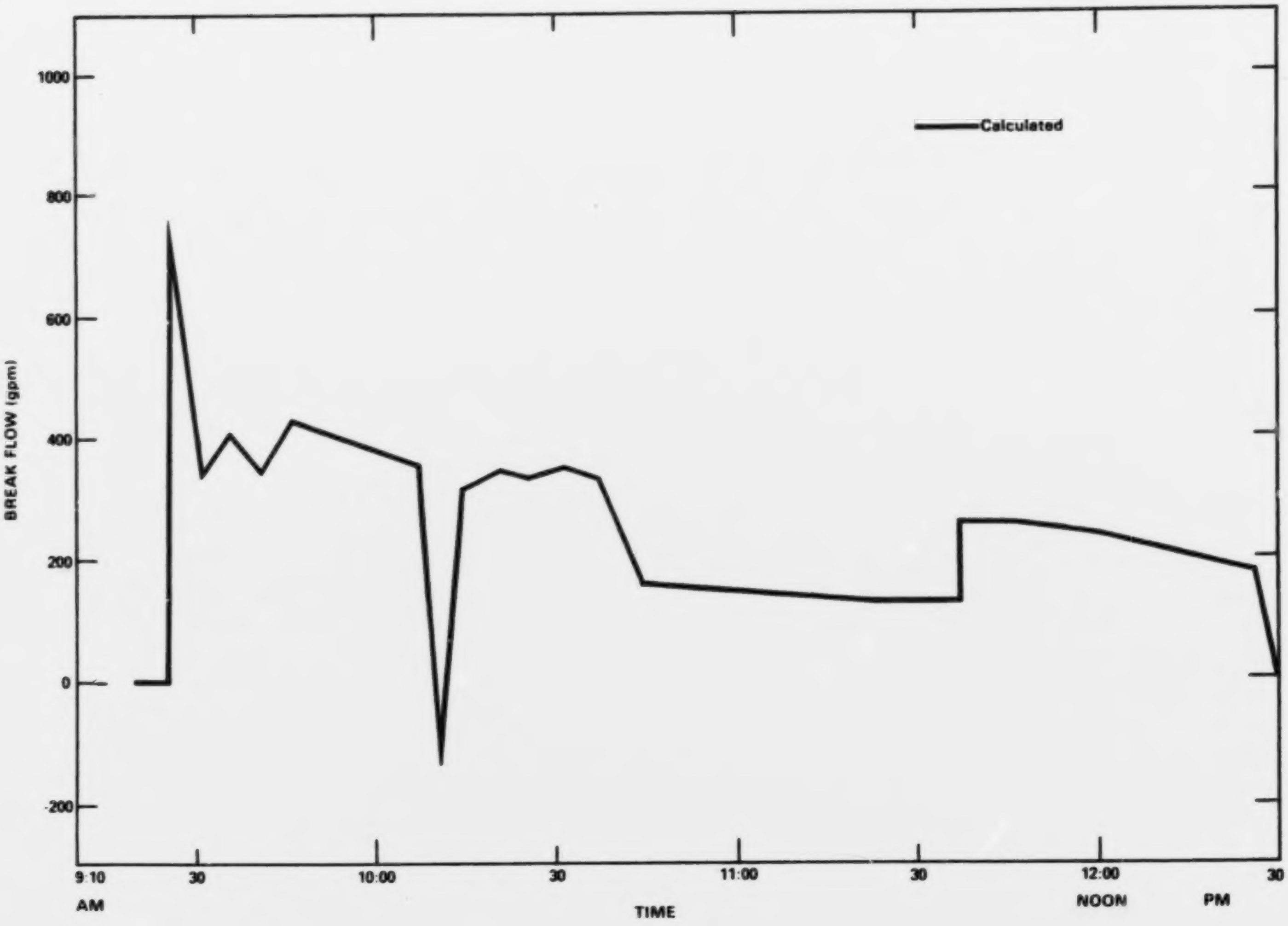

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Figure 3.5 Steam generator tube leakage as a function of time, January 25, 1982

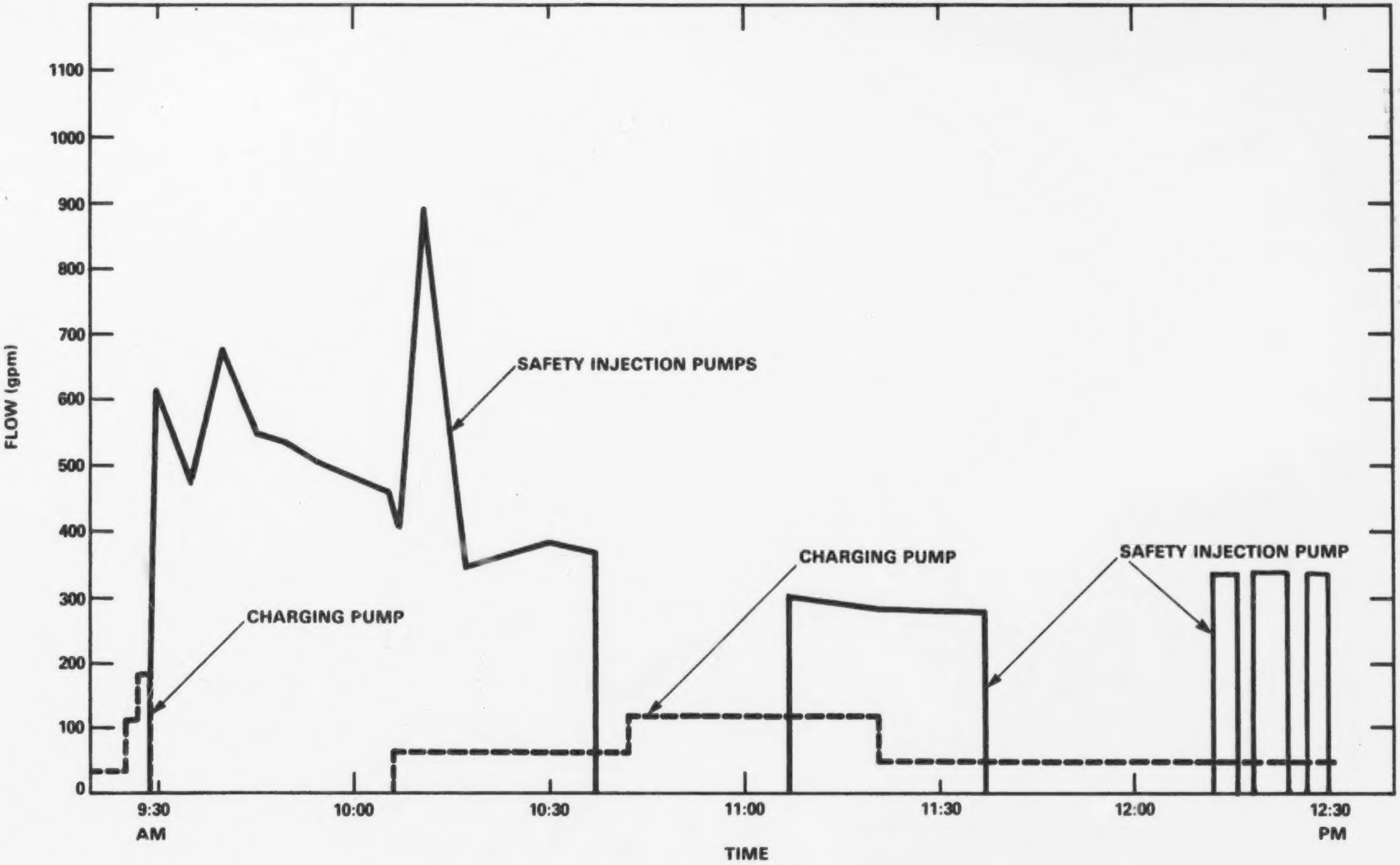

Figure 3.6 Safety injection and charging flow rate as a function of time, January 25, 1982

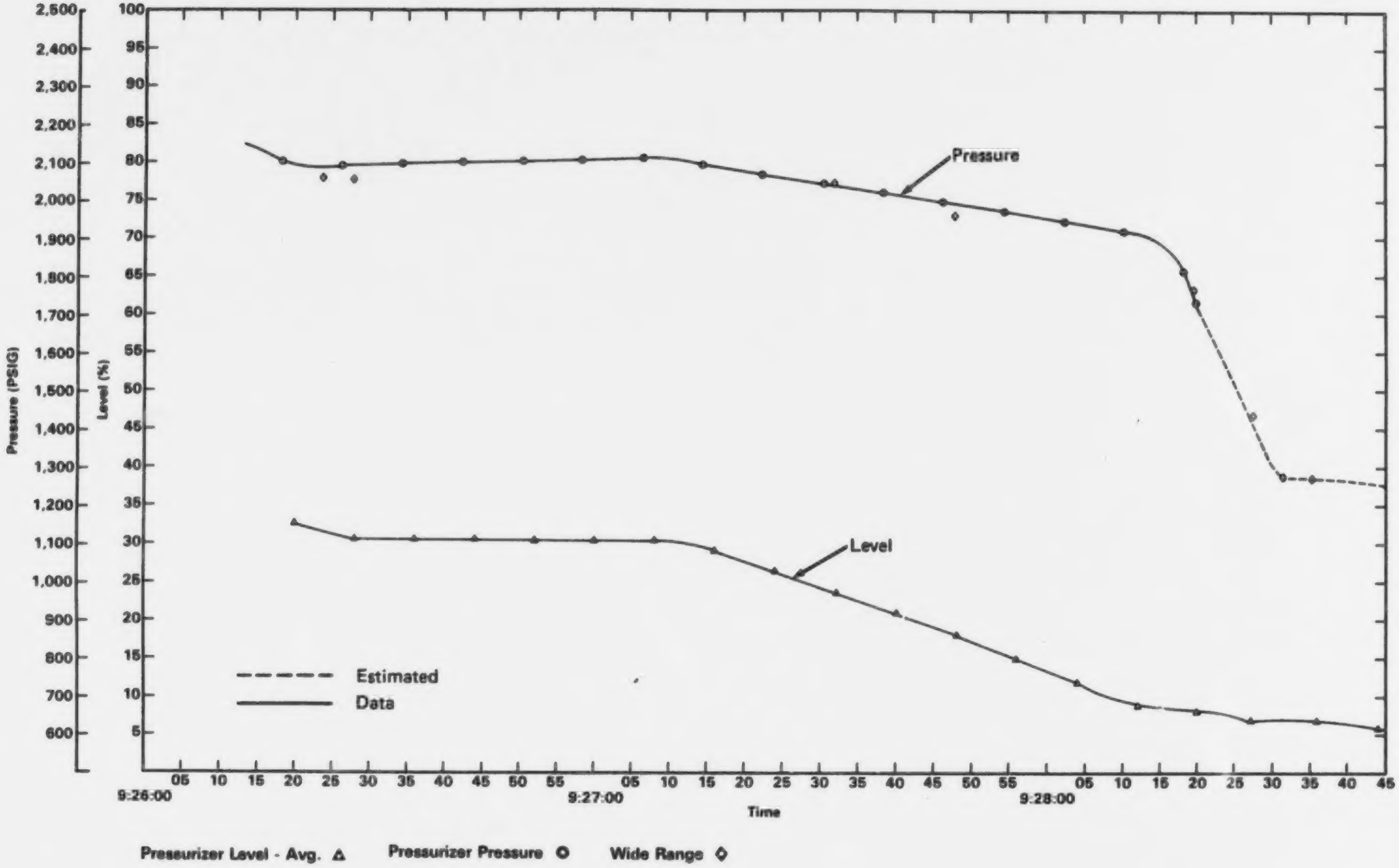

Figure 3.7 Initial depressurization pressurizer level and pressure as a function of time, January 25, 1982

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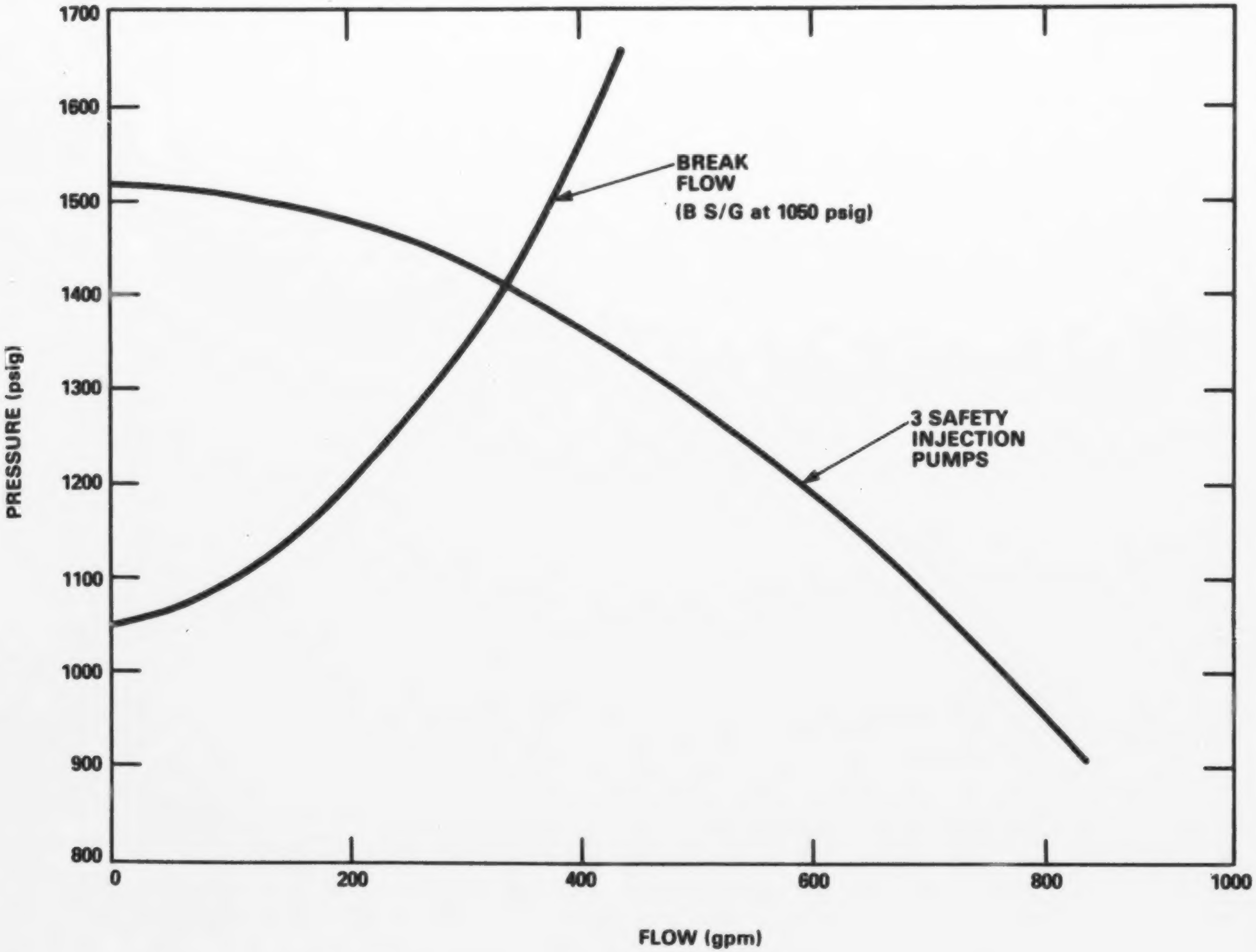

Figure 3.8 Safety injection and break flow as a function of pressure

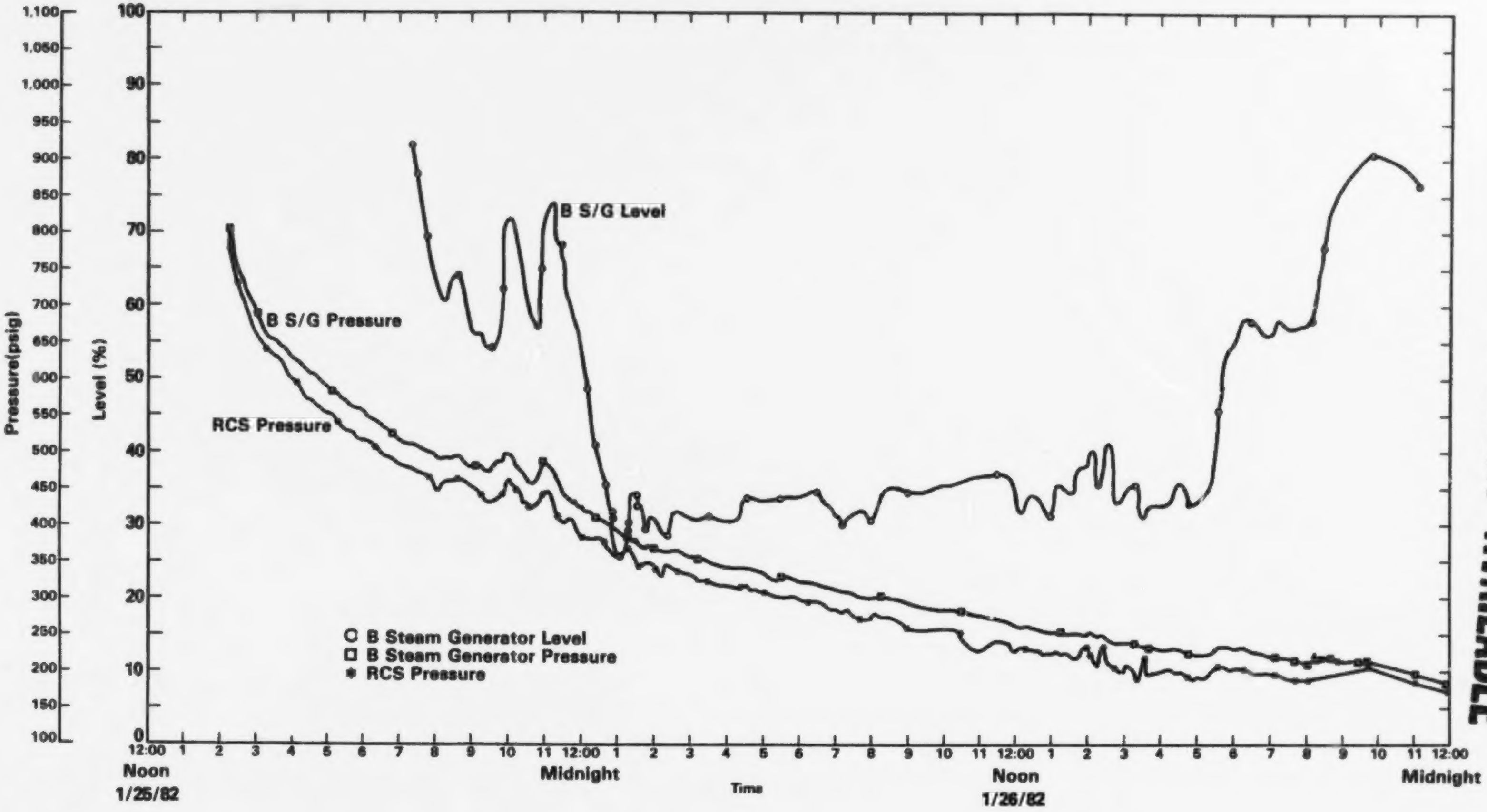

Figure 3.9 Long-term cooldown and depressurization of reactor coolant loop and B steam generator pressure as a function of time, January 25 and 26, 1982

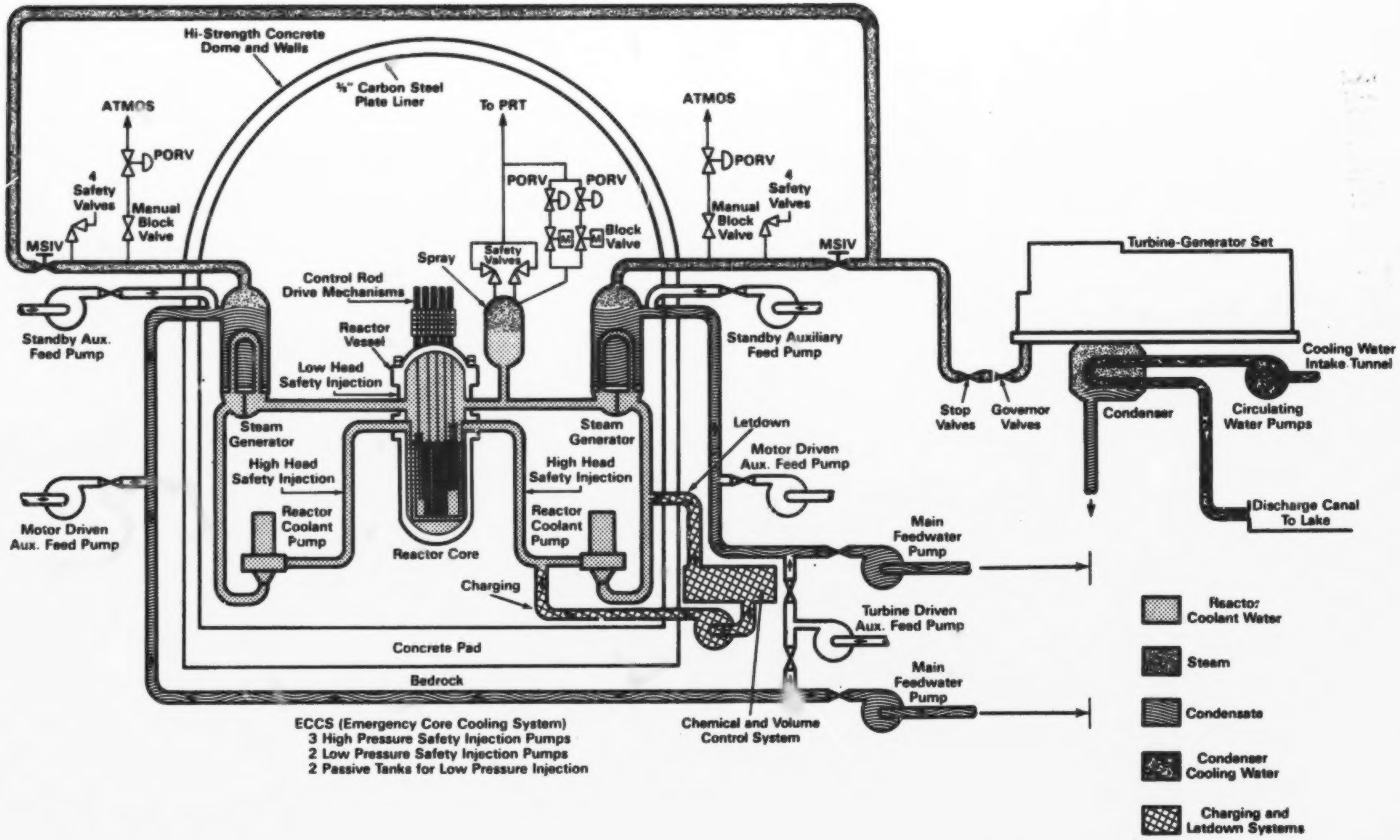
Hi-Strength Concrete Dome and Walls
⅜" Carbon Steel Plate Liner
ATMOS
PORV
4 Safety Valves
Manual Block Valve
MSIV
To PRT
PORV
PORV
Block Valve
Safety Valves
Spray
Control Rod Drive Mechanisms
Reactor Vessel
Low Head Safety Injection
ATMOS
PORV
Manual Block Valve
4 Safety Valves
MSIV
Turbine-Generator Set
Standby Aux. Feed Pump
Standby Auxiliary Feed Pump
Steam Generator
Steam Generator
High Head Safety Injection
High Head Safety Injection
Reactor Coolant Pump
Reactor Coolant Pump
Reactor Core
Charging
Letdown
Motor Driven Aux. Feed Pump
Motor Driven Aux. Feed Pump
Stop Valves
Governor Valves
Condenser
Cooling Water Intake Tunnel
Circulating Water Pumps
Discharge Canal To Lake
Main Feedwater Pump
Turbine Driven Aux. Feed Pump
Main Feedwater Pump
Concrete Pad
Bedrock
Chemical and Volume Control System
ECCS (Emergency Core Cooling System)
3 High Pressure Safety Injection Pumps
2 Low Pressure Safety Injection Pumps
2 Passive Tanks for Low Pressure Injection
Reactor Coolant Water
Steam
Condensate
Condenser Cooling Water
Charging and Letdown Systems

Figure 3.10 Schematic diagram of Westinghouse-designed pressurized water reactor of Rochester Gas & Electric Corporation's Ginna Nuclear Power Plant

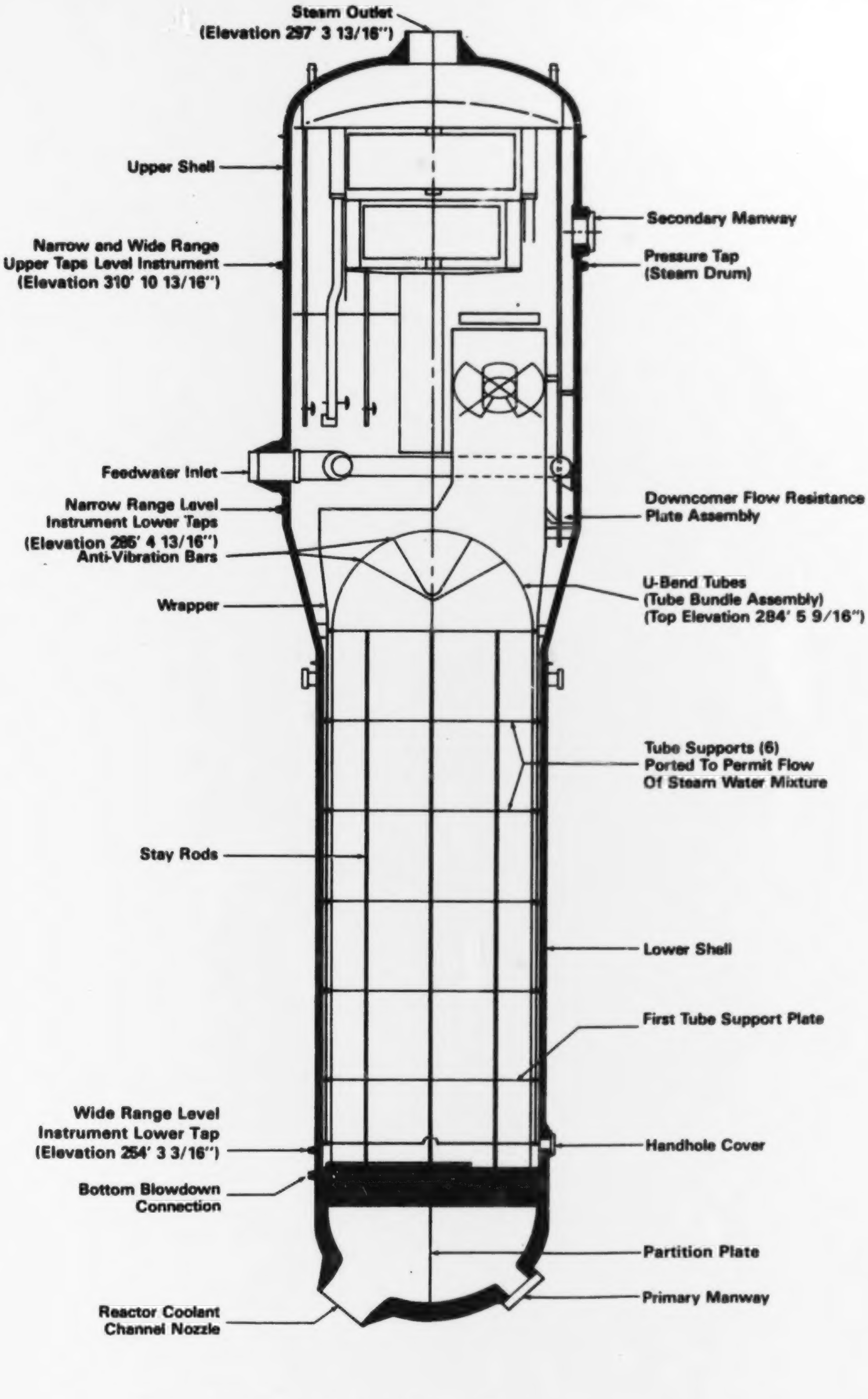
Steam Outlet
(Elevation 297' 3 13/16")
Upper Shell
Secondary Manway
Narrow and Wide Range
Upper Taps Level Instrument
(Elevation 310' 10 13/16")
Pressure Tap
(Steam Drum)
Feedwater Inlet
Narrow Range Level
Instrument Lower Taps
(Elevation 285' 4 13/16")
Downcomer Flow Resistance
Plate Assembly
Anti-Vibration Bars
Wrapper
U-Bend Tubes
(Tube Bundle Assembly)
(Top Elevation 284' 5 9/16")
Tube Supports (6)
Ported To Permit Flow
Of Steam Water Mixture
Stay Rods
Lower Shell
First Tube Support Plate
Wide Range Level
Instrument Lower Tap
(Elevation 254' 3 3/16")
Handhole Cover
Bottom Blowdown
Connection
Partition Plate
Primary Manway
Reactor Coolant
Channel Nozzle

Figure 3.11 Ginna Nuclear Power Plant steam generator

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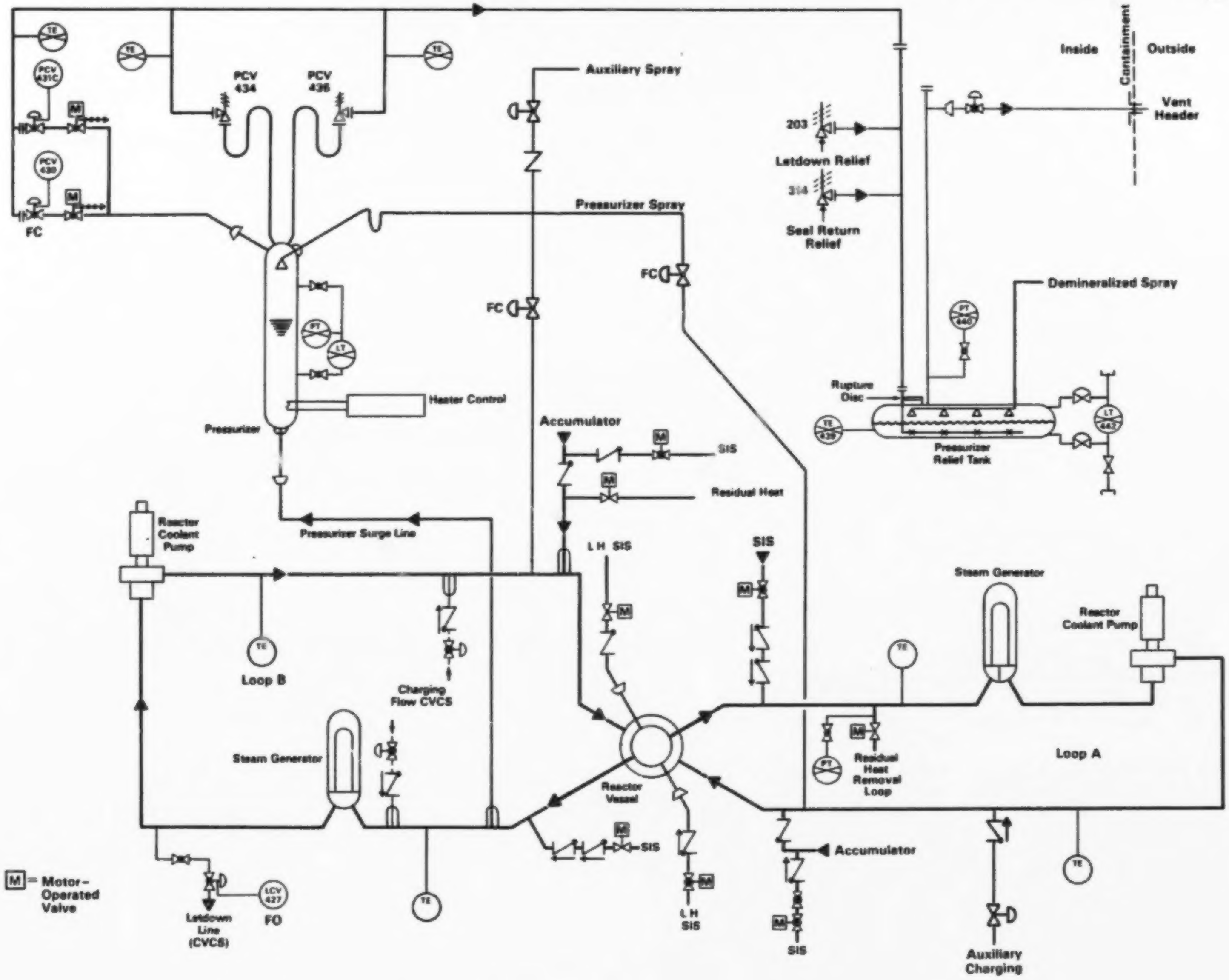
TE
PCV 431C
M
PCV 430
M
FC
TE
PCV 434
PCV 435
TE
Auxiliary Spray
Pressurizer Spray
FC
FC
PT
LT
Heater Control
Pressurizer
Accumulator
M
SIS
M
Residual Heat
Reactor Coolant Pump
Pressurizer Surge Line
L H SIS
SIS
M
M
TE
Loop B
Charging Flow CVCS
Steam Generator
Reactor Vessel
M
SIS
M
L H SIS
Accumulator
M
SIS
Letdown Line (CVCS)
LCV 427
FO
M = Motor-Operated Valve
TE
Inside
Containment
Outside
Vent Header
203
Letdown Relief
314
Seal Return Relief
Demineralized Spray
PT 440
Rupture Disc
TE 439
Pressurizer Relief Tank
LT 442
Steam Generator
Reactor Coolant Pump
TE
M
PT
Residual Heat Removal Loop
Loop A
TE
Auxiliary Charging

Figure 3.12 Ginna Nuclear Power Plant piping and instrumentation diagram

REACTOR COOLANT SYSTEM ELEVATIONS AND INSTRUMENTATION

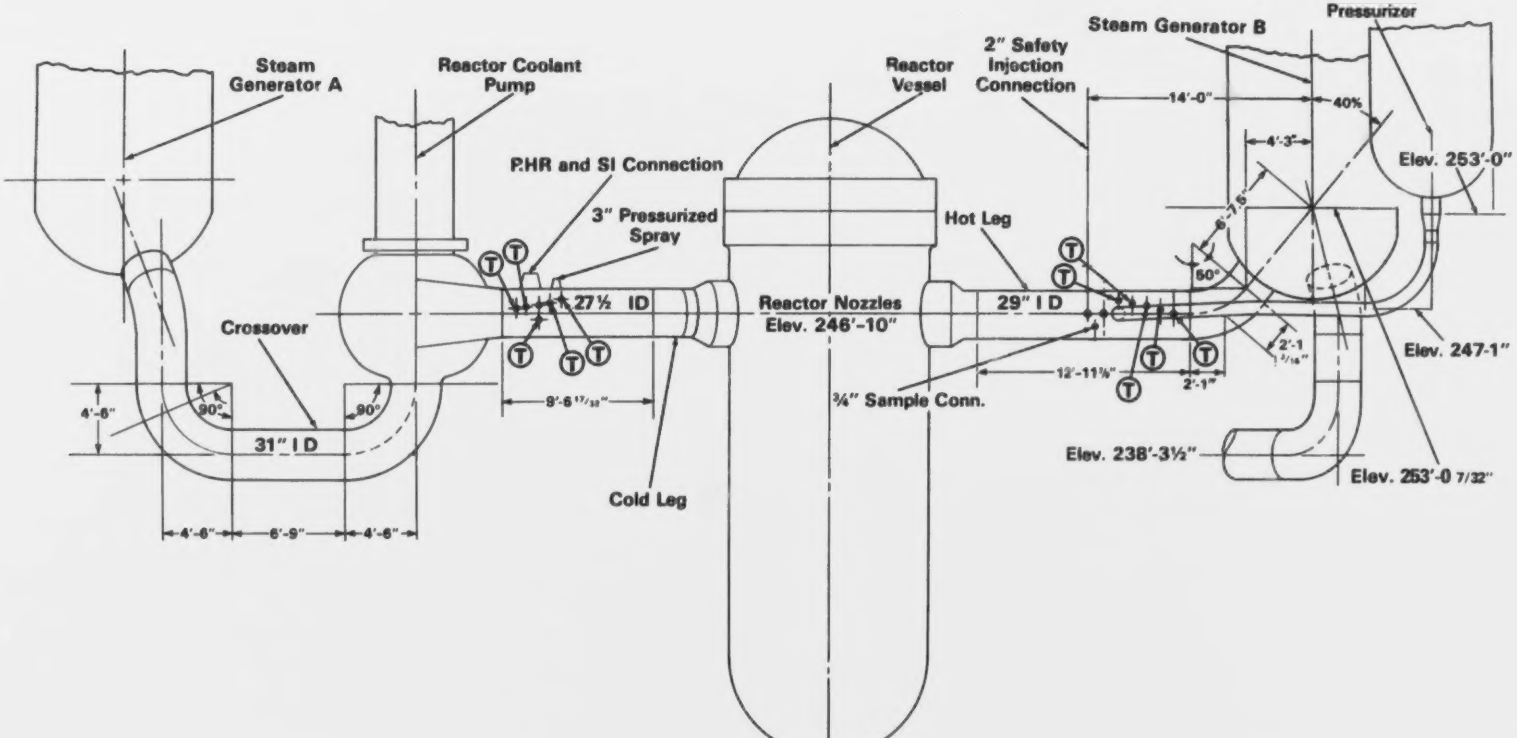
Steam Generator A
Reactor Coolant Pump
Reactor Vessel
2" Safety Injection Connection
Steam Generator B
Pressurizer
14'-0"
40%
4'-3"
Elev. 253'-0"
6'-7.5"
50°
P.HR and SI Connection
3" Pressurized Spray
Hot Leg
27½ ID
Reactor Nozzles Elev. 246'-10"
29" I D
Crossover
4'-6"
90°
90°
31" I D
9'-6 17/32"
¾" Sample Conn.
12'-11⅞"
2'-1"
2'-1 1 3/16"
Elev. 247-1"
Elev. 238'-3½"
Elev. 253'-0 7/32"
Cold Leg
4'-6"
6'-9"
4'-6"
T

Figure 3.13 Reactor coolant system components and elevations

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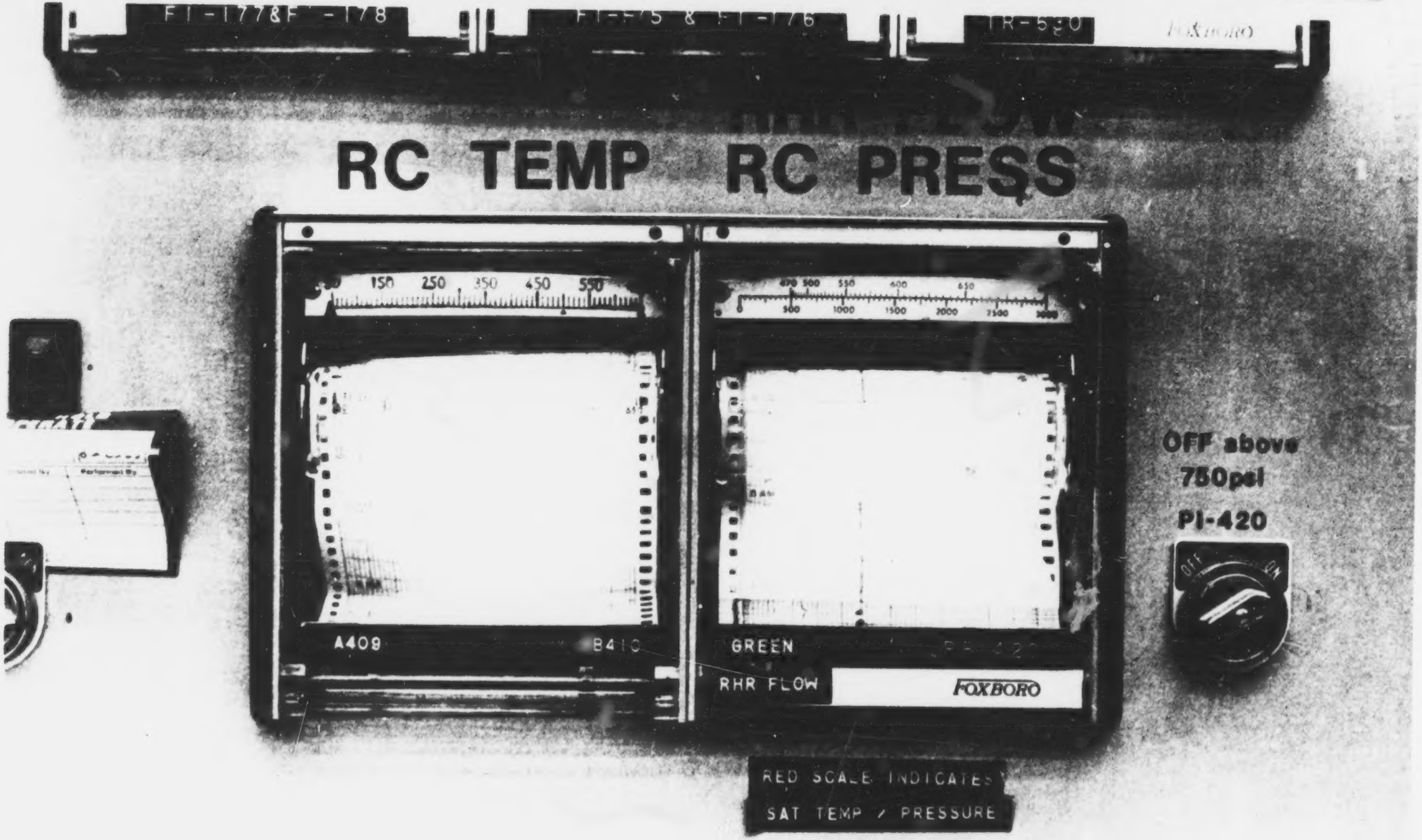

FI-177&FI-178
FI-175 & FI-176
TR-530
FOXBORO
RHR FLOW
RC TEMP
RC PRESS
150
250
350
450
550
470
500
550
600
650
0
500
1000
1500
2000
2500
3000
A409
B410
GREEN
RHR FLOW
FOXBORO
OFF above
750psi
PI-420
OFF
ON
RED SCALE INDICATES
SAT TEMP / PRESSURE

Figure 3.14 Reactor coolant system temperature and pressure recorders

BEST DOCUMENT AVAILABLE

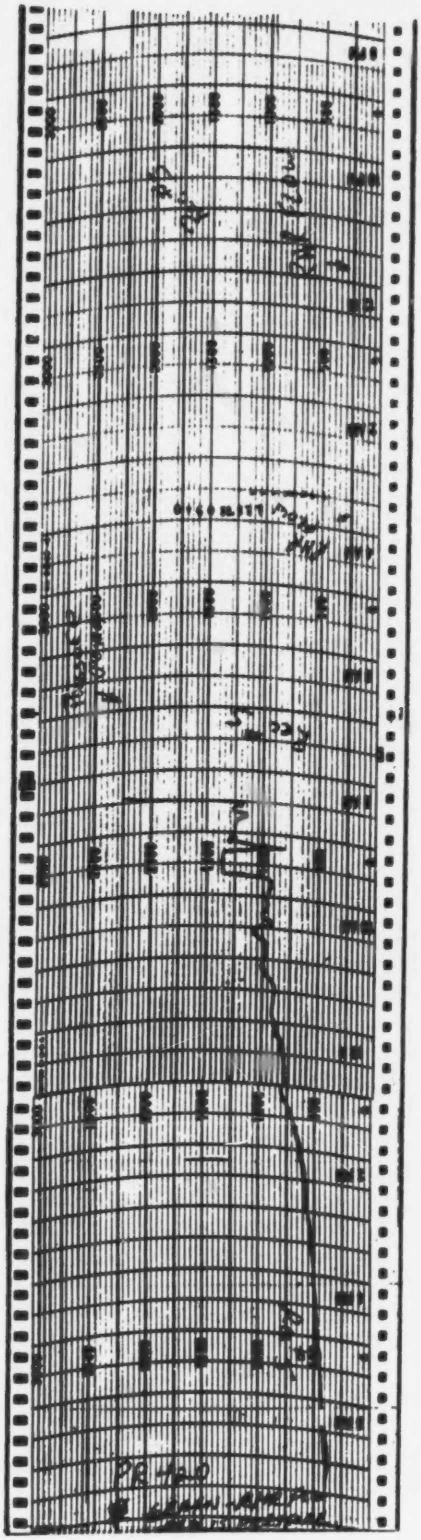


Figure 3.15 Reactor coolant system pressure trace

BEST DOCUMENT AVAILABLE

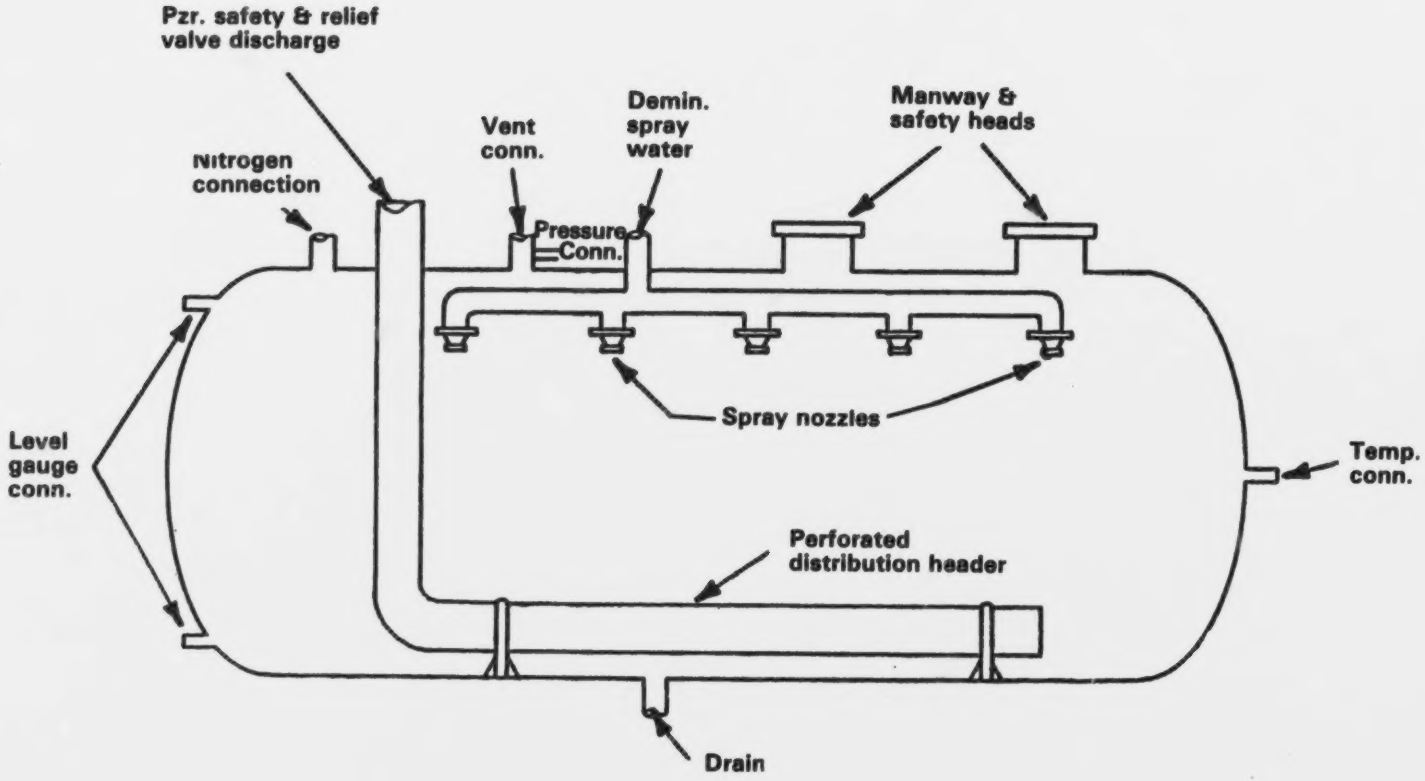

Pzr. safety & relief valve discharge
Vent conn.
Demin. spray water
Manway & safety heads
Nitrogen connection
Pressure Conn.
Spray nozzles
Level gauge conn.
Temp. conn.
Perforated distribution header
Drain

Figure 3.16 Pressurizer relief tank

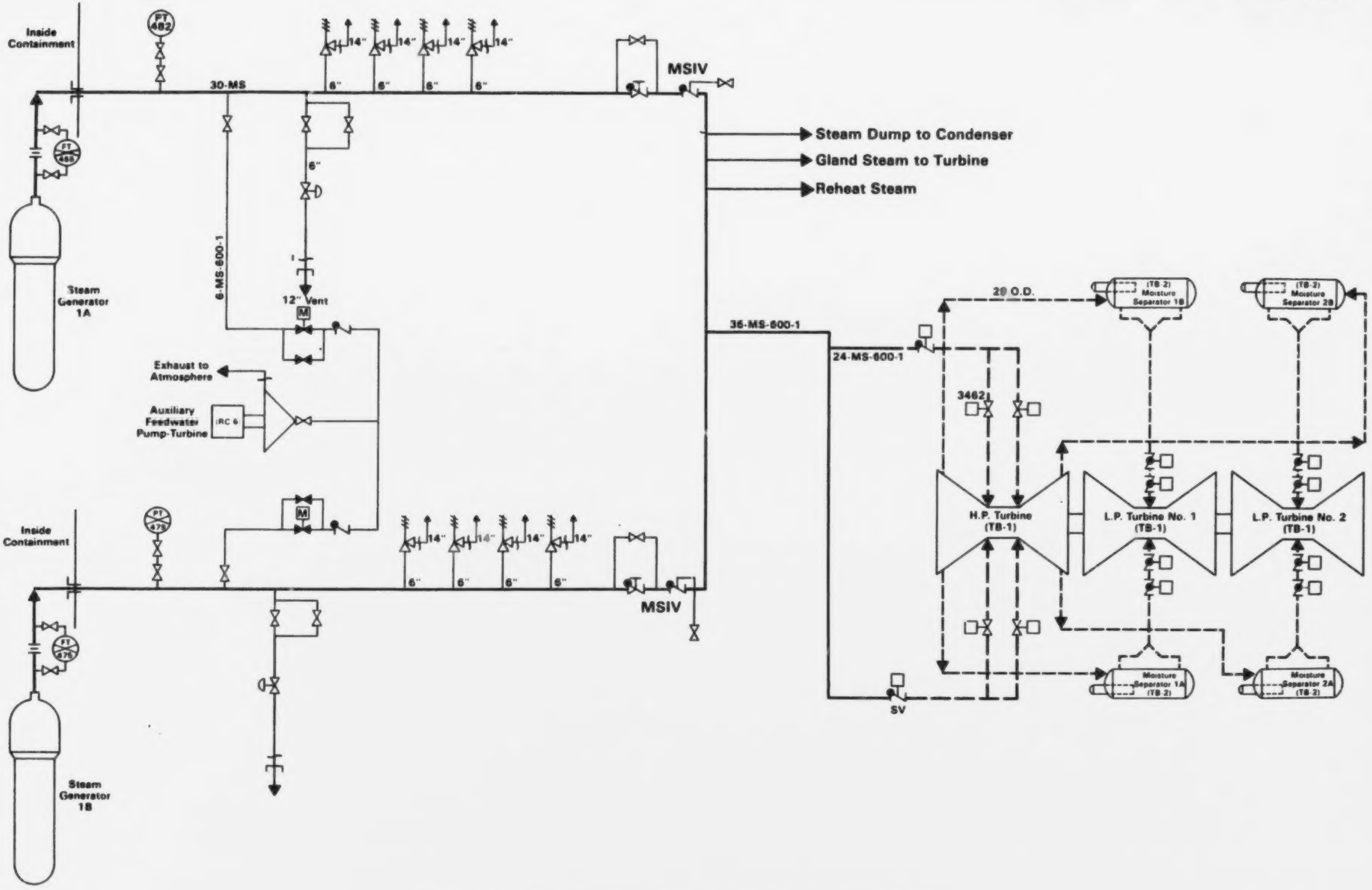

Inside Containment
PT 482
30-MS
14"
14"
14"
14"
6"
6"
6"
6"
MSIV
Steam Dump to Condenser
Gland Steam to Turbine
Reheat Steam
FT 466
6"
6-MS-600-1
12" Vent
M
Steam Generator 1A
Exhaust to Atmosphere
Auxiliary Feedwater Pump-Turbine
RC 6
36-MS-600-1
24-MS-600-1
28 O.D.
(TB-2) Moisture Separator 1B
(TB-2) Moisture Separator 2B
3462
H.P. Turbine (TB-1)
L.P. Turbine No. 1 (TB-1)
L.P. Turbine No. 2 (TB-1)
M
Inside Containment
PT 475
14"
14"
14"
14"
6"
6"
6"
6"
MSIV
FT 475
Moisture Separator 1A (TB-2)
Moisture Separator 2A (TB-2)
SV
Steam Generator 1B

Figure 3.17 Flow diagram of main and reheat steam system

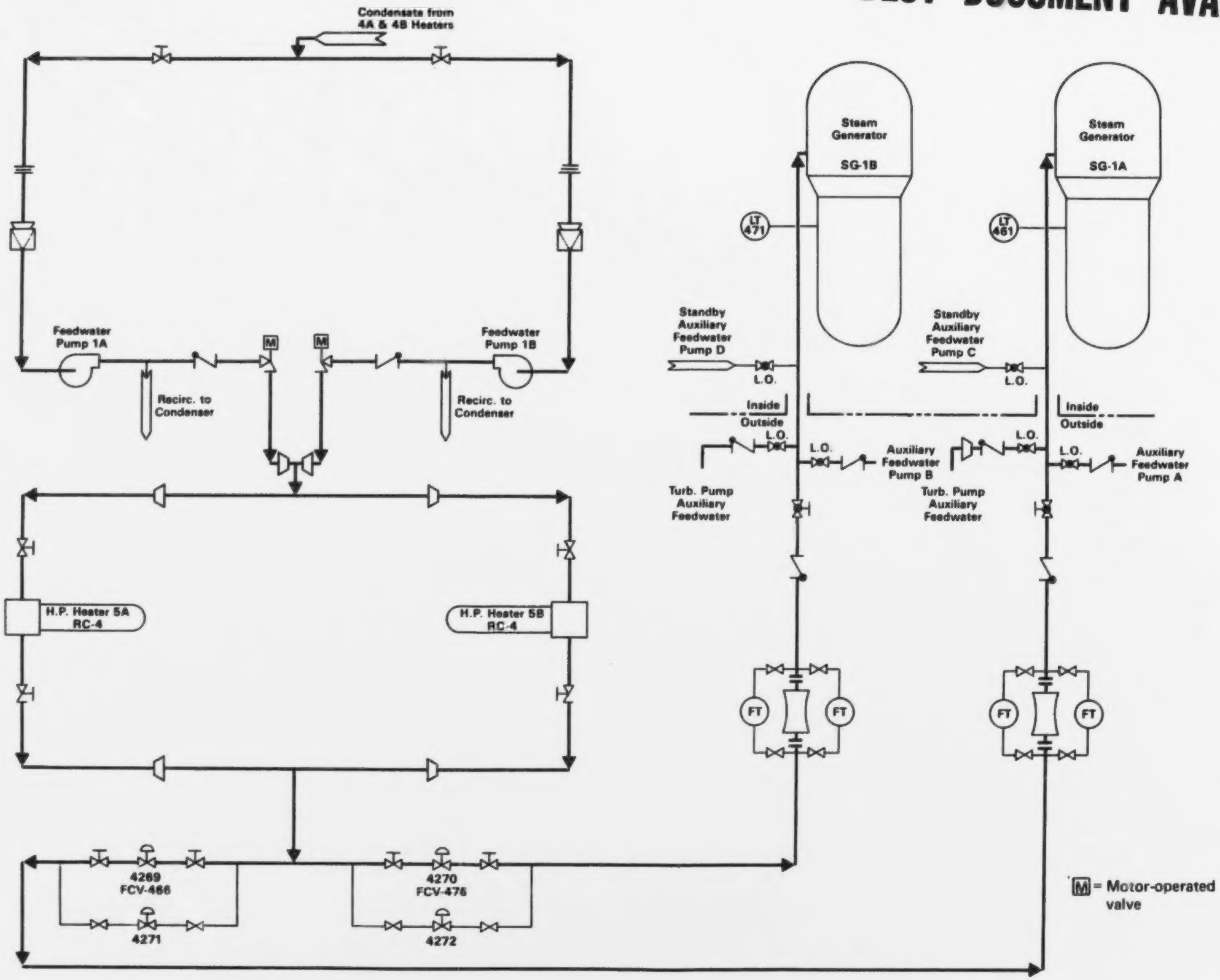
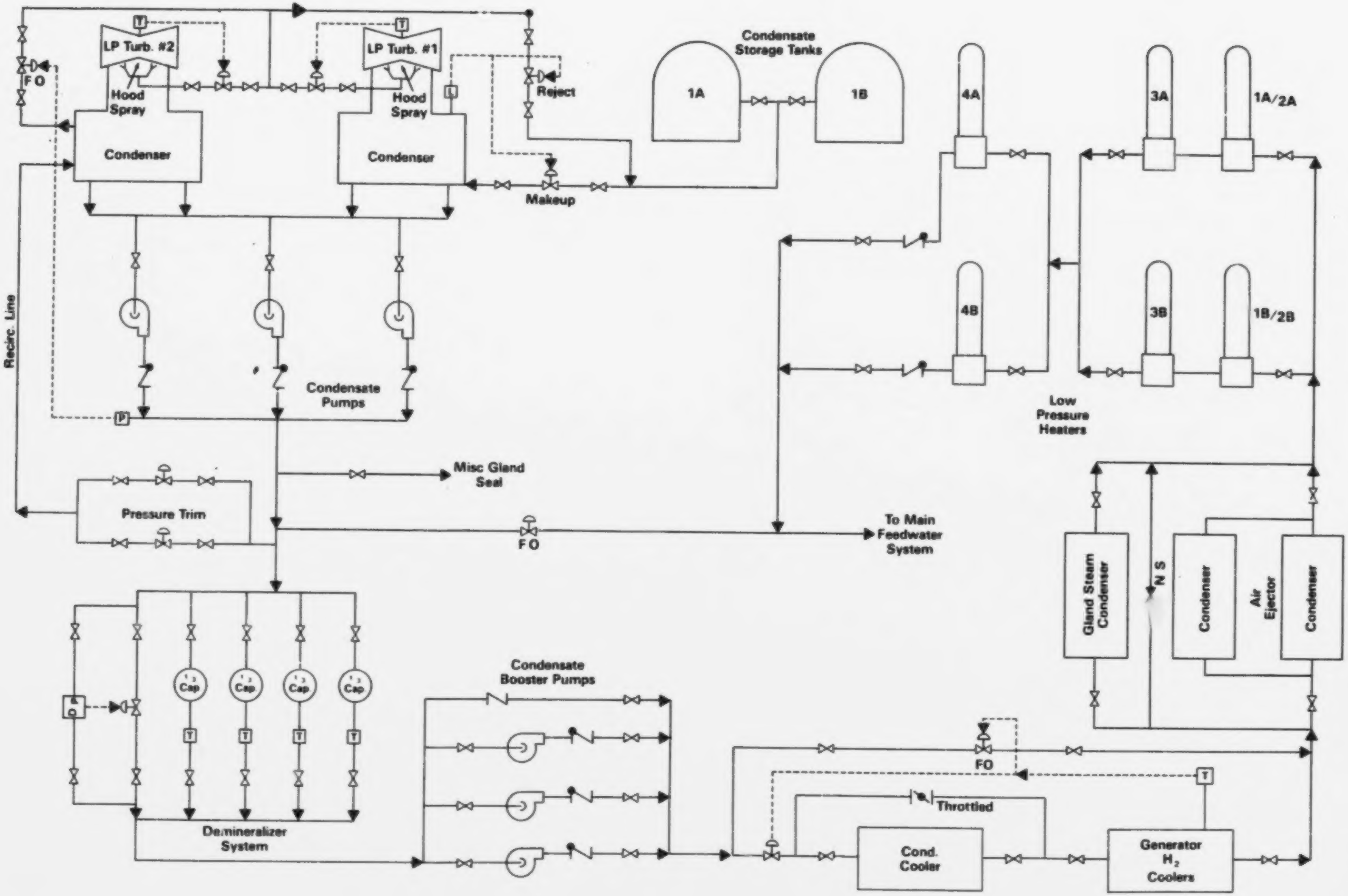

Condensate from 4A & 4B Heaters
Feedwater Pump 1A
Feedwater Pump 1B
M
M
Recirc. to Condenser
Recirc. to Condenser
H.P. Heater 5A RC-4
H.P. Heater 5B RC-4
4269 FCV-466
4271
4270 FCV-476
4272
Steam Generator SG-1B
Steam Generator SG-1A
LT 471
LT 461
Standby Auxiliary Feedwater Pump D
Standby Auxiliary Feedwater Pump C
L.O.
L.O.
Inside
Outside
Inside
Outside
L.O.
L.O.
Auxiliary Feedwater Pump B
L.O.
L.O.
Auxiliary Feedwater Pump A
Turb. Pump Auxiliary Feedwater
Turb. Pump Auxiliary Feedwater
FT
FT
FT
FT
M = Motor-operated valve

Figure 3.18 Flow diagram of main feedwater system



LP Turb. #2
LP Turb. #1
T
Hood Spray
Hood Spray
F O
Condenser
Condenser
L
Reject
Makeup
Condensate Storage Tanks
1A
1B
4A
3A
1A/2A
4B
3B
1B/2B
Low Pressure Heaters
Recirc. Line
Condensate Pumps
P
Misc Gland Seal
Pressure Trim
F O
To Main Feedwater System
Gland Steam Condenser
N S
Condenser
Air Ejector
Condenser
Cap
Demineralizer System
Condensate Booster Pumps
FO
Throttled
Cond. Cooler
Generator H₂ Coolers

Figure 3.19 Flow diagram of condensate system

BEST DOCUMENT AVAILABLE

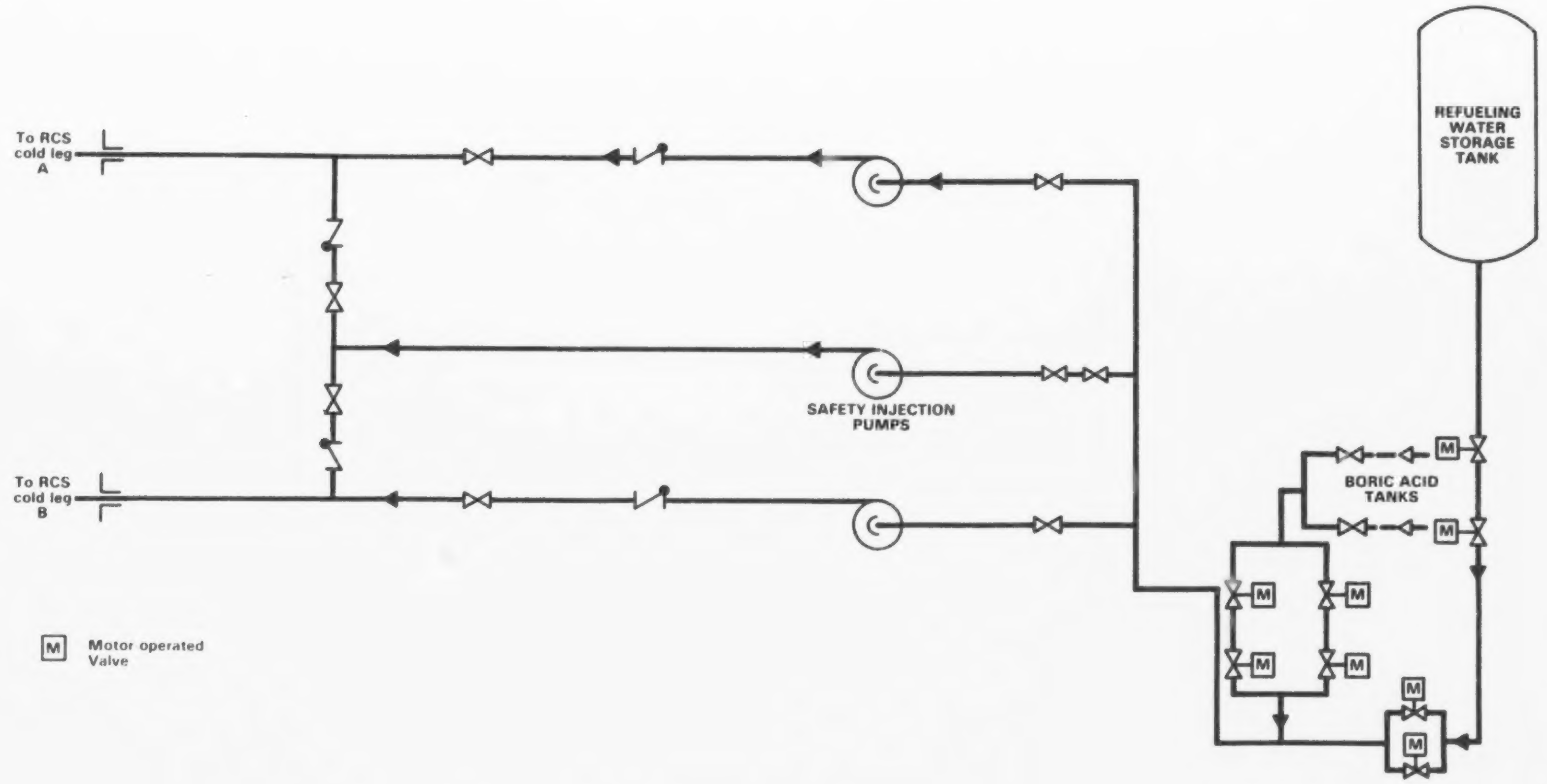

To RCS
cold leg
A
To RCS
cold leg
B
REFUELING
WATER
STORAGE
TANK
SAFETY INJECTION
PUMPS
BORIC ACID
TANKS
M
M Motor operated
Valve

Figure 3.20 Flow diagram of the high-pressure portion of the safety injection system

BEST DOCUMENT AVAILABLE

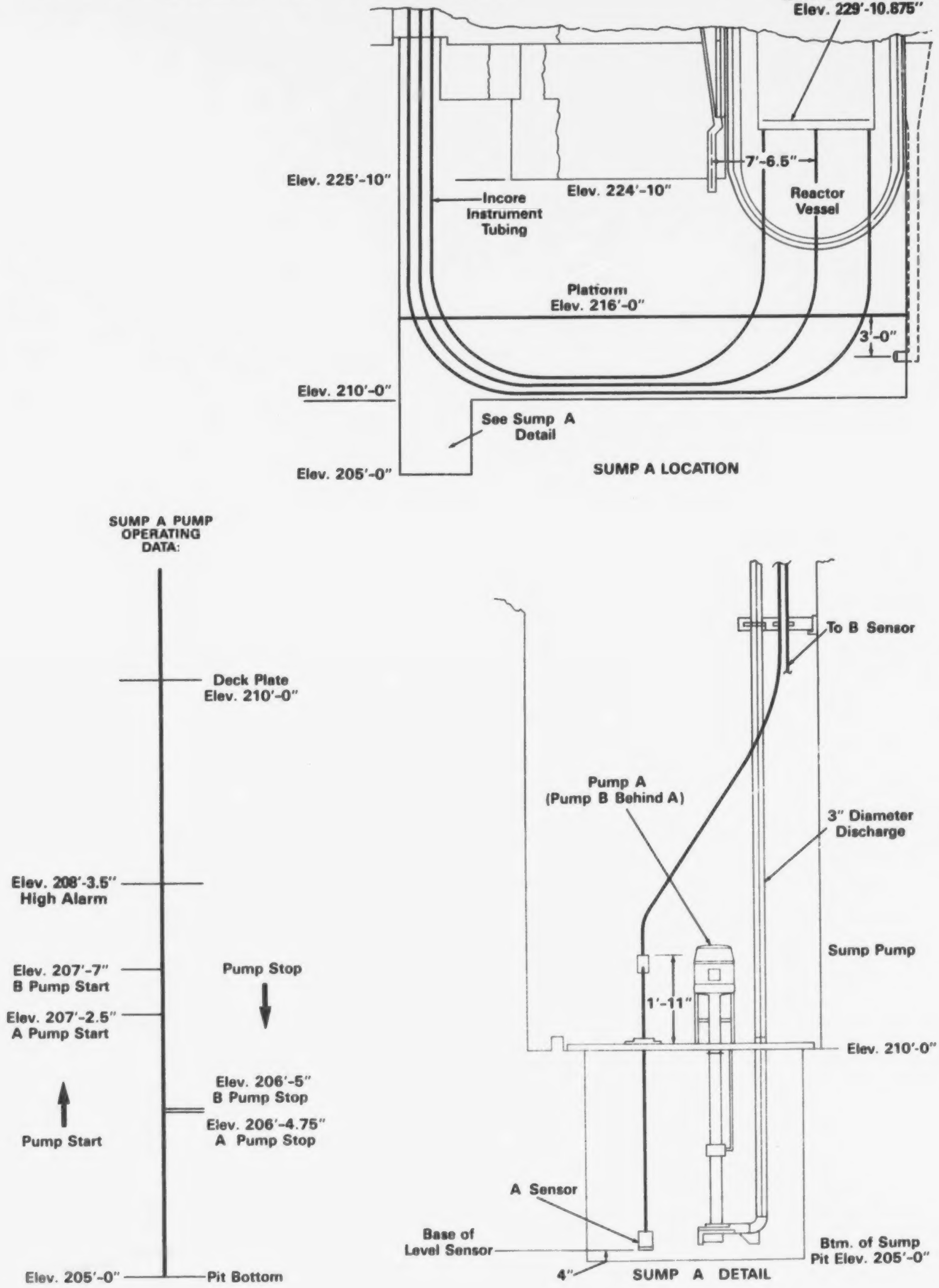

Btm. of Active Fuel
Elev. 229'-10.875"
7'-6.5"
Reactor Vessel
Elev. 225'-10"
Elev. 224'-10"
Incore Instrument Tubing
Platform Elev. 216'-0"
3'-0"
Elev. 210'-0"
See Sump A Detail
Elev. 205'-0"
SUMP A LOCATION
SUMP A PUMP OPERATING DATA:
Deck Plate Elev. 210'-0"
Elev. 208'-3.5" High Alarm
Elev. 207'-7" B Pump Start
Elev. 207'-2.5" A Pump Start
Pump Stop
Elev. 206'-5" B Pump Stop
Elev. 206'-4.75" A Pump Stop
Pump Start
Elev. 205'-0"
Pit Bottom
To B Sensor
Pump A (Pump B Behind A)
3" Diameter Discharge
Sump Pump
1'-11"
Elev. 210'-0"
A Sensor
Base of Level Sensor
Btm. of Sump Pit Elev. 205'-0"
4"
SUMP A DETAIL

Figure 3.21 Containment sump A

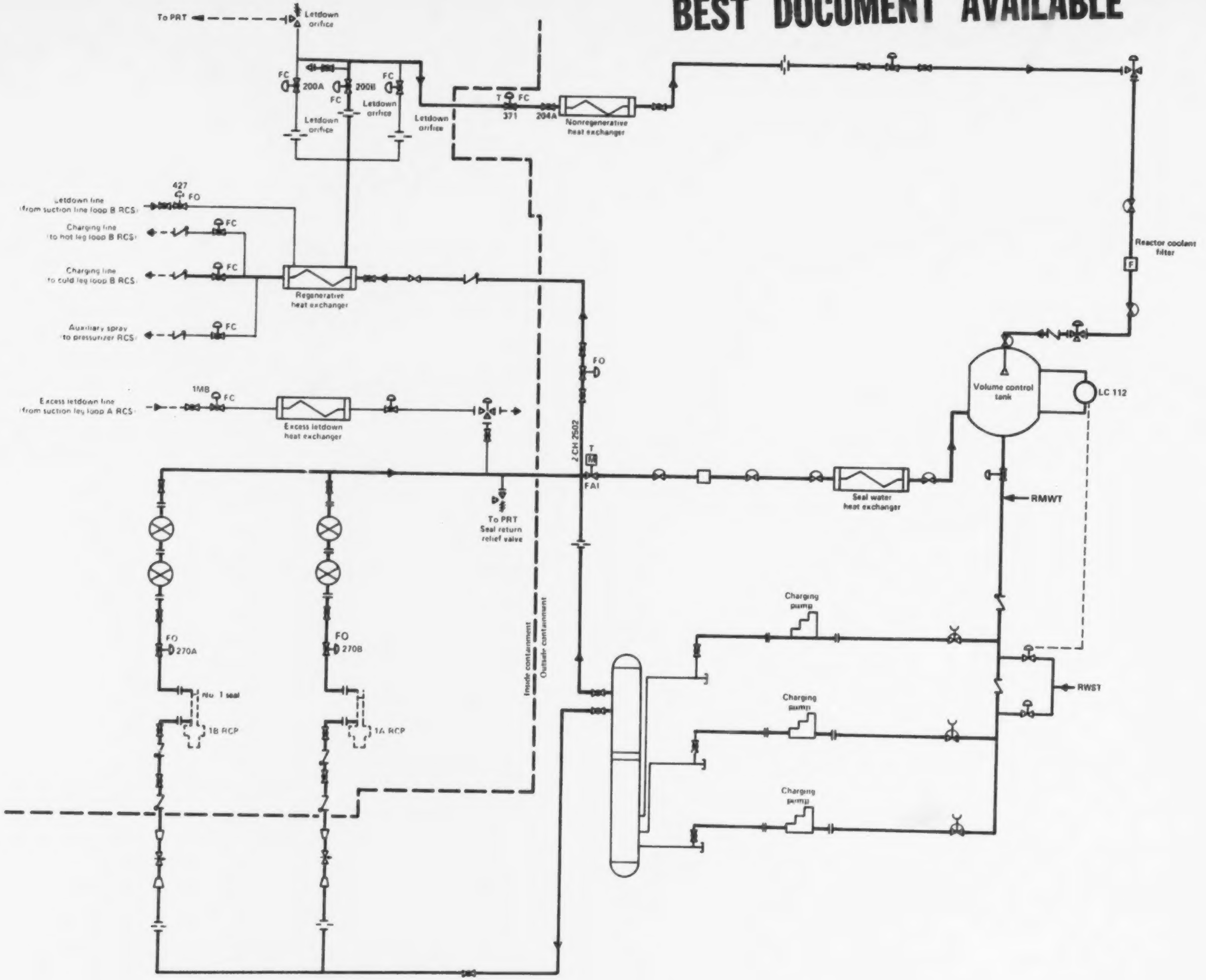

To PRT
Letdown orifice
FC
200A
200B
FC
FC
Letdown orifice
Letdown orifice
Letdown orifice
T
FC
371
204A
Nonregenerative heat exchanger
427
FO
Letdown line (from suction line loop B RCS)
Charging line (to hot leg loop B RCS)
FC
Charging line (to cold leg loop B RCS)
FC
Regenerative heat exchanger
Auxiliary spray (to pressurizer RCS)
FC
FO
Reactor coolant filter
F
Volume control tank
LC 112
1MB
FC
Excess letdown line (from suction leg loop A RCS)
Excess letdown heat exchanger
2 CH 2502
T
M
FAI
Seal water heat exchanger
RMWT
To PRT Seal return relief valve
Inside containment
Outside containment
FO
270A
FO
270B
No. 1 seal
1B RCP
1A RCP
Charging pump
Charging pump
Charging pump
RWST

Figure 3.22 Chemical and volume control system

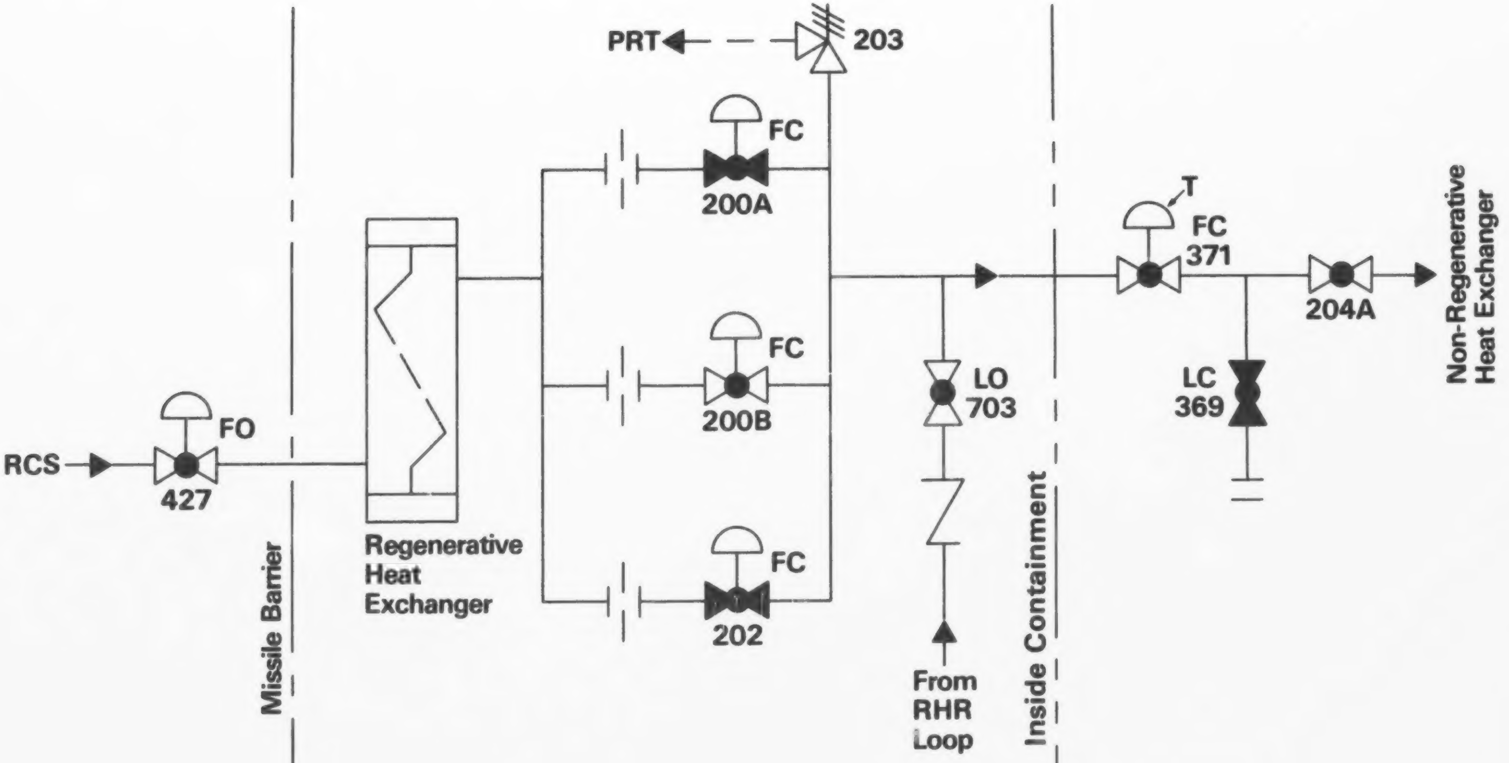

PRT
203
FC
200A
FC
200B
FC
202
T
FC
371
204A
Non-Regenerative
Heat Exchanger
LO
703
LC
369
FO
RCS
427
Missile Barrier
Regenerative
Heat
Exchanger
From
RHR
Loop
Inside Containment

Figure 3.23 Diagram of letdown line isolation and relief valves

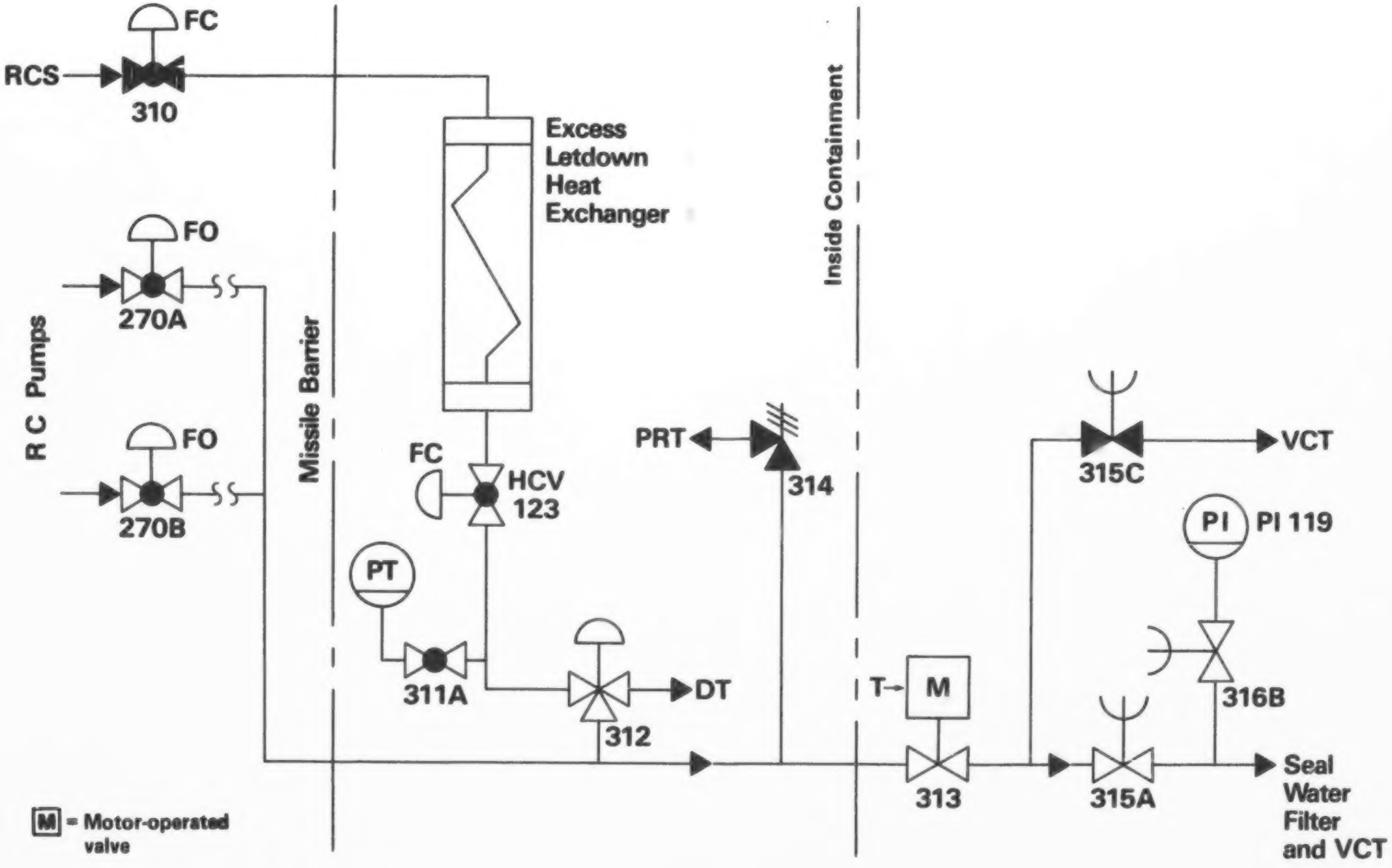

FC
RCS
310
Excess
Letdown
Heat
Exchanger
Inside Containment
FO
270A
R C Pumps
Missile Barrier
FO
270B
FC
HCV
123
PRT
314
315C
VCT
PI
PI 119
PT
311A
312
DT
T
M
313
315A
316B
Seal
Water
Filter
and VCT
M = Motor-operated
valve

Figure 3.24 Diagram of reactor coolant pump seal water return line isolation and relief valves

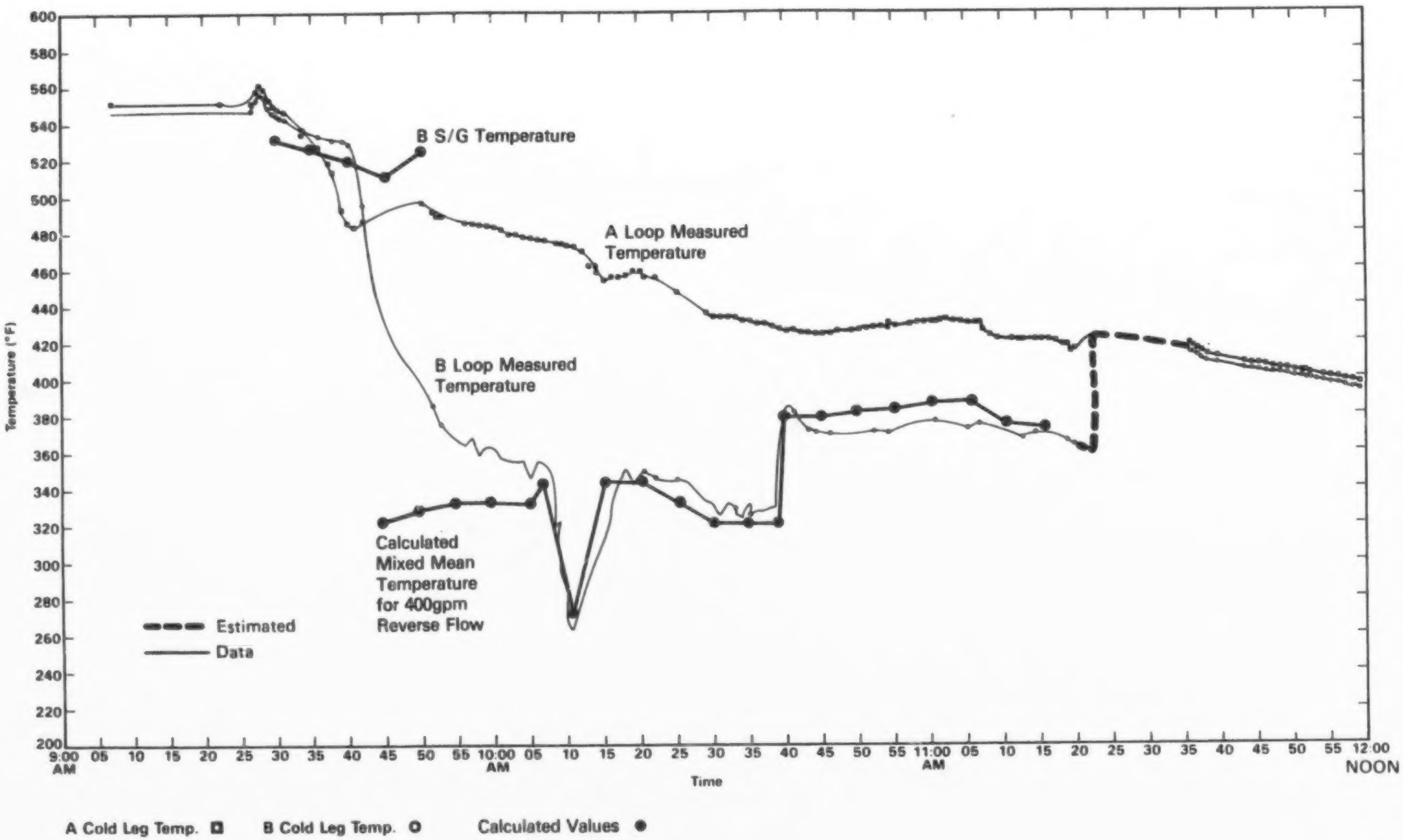


Figure 3.25 Reactor coolant loop cold-leg temperature compared with calculated values, January 25, 1982

4 HUMAN FACTORS CONSIDERATIONS

4.1 Facilities

4.1.1 General

This section provides a brief description from a human factors perspective of the Ginna control room and Technical Support Center (TSC) as they related to the steam generator tube rupture event. The information was obtained through interviews with the plant staff, a review of the control room and Technical Support Center relative to human factors design guidelines,* and informal partial walk-throughs of the event with several licensed operators.

Unless indicated otherwise, problems identified in the following sections were not shown to affect this event adversely.

4.1.2 Control Room

4.1.2.1 General Layout

The Ginna control room is located off the turbine deck in a controlled access area. Figure 4.1 shows a general layout of the area, with major system panels, communications, furnishings, and other equipment identified.

The primary operating area was found to be compact and laid out to minimize operator movement and maximize access to the control boards. All pathways around desks, consoles, and other equipment were at least 3 ft wide and provided adequate clearance for unobstructed movement. The Shift Supervisor's

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*NUREG-0700, "Guidelines for Control Room Design Reviews," U.S. Nuclear Regulatory Commission, September 1981.

Office was located so as to permit direct access to the primary operating area and to facilitate control of persons entering the controlled-access space.

4.1.2.2 Work Station Design

The primary operating area (Figure 4.2) consisted of a three-section horseshoe-shaped standup console that provided approximately 25 linear ft of benchboard, vertical display panel, and annunciator panel. Although the consoles exceeded the dimensions for good anthropometric design in benchboard depth and vertical panel height, all controls were within the extended reach of the Ginna operators. The frontmost controls on the benchboard were set well back from the front edge so that an operator leaning over the board would not inadvertently actuate any control. The topmost displays on the vertical portion of the left wing and center standup consoles (Figures 4.3 and 4.4) were higher than human factors design guidelines recommend, but could be read accurately from the normal standing position in front of the display.

Several displays and controls on the back vertical panels (Figures 4.5 and 4.6) were located outside the range of good design, but could be read or reached by Ginna operators without undue difficulty.

Operating procedures were contained in labeled looseleaf binders and were stored on open bookshelves (Figure 4.7) located as shown on Figure 4.1. The correct place for each binder was marked on the front edge of the shelf using the same terminology as on the binder edge. Normal procedures were kept in black binders. Emergency procedures and the index volume for all procedures were shelved in red binders. When it was necessary to follow a procedure while working at the main control console, the procedure was laid out on either of the Control Operators' desks. During the steam generator tube rupture event, the Shift Technical Advisor sat at the Head Control Operator's desk and read the procedure aloud, freeing the Control Operators to concentrate on the displays and perform required control actions.

4.1.2.3 Environment

The temperature, humidity, ventilation, illumination, and auditory environment in the control room were found to be within satisfactory human factors design limits during the NRC Task Force review on February 21-22, 1982. No information was developed that indicated conditions differed during the event.

4.1.2.4 Voice Communications

All plant communications systems worked well during this event and no equipment problems were reported during interviews with the operators or technical staff. A sound-powered, battery-assisted direct line from the control room to several specific plant locations (e.g., the Technical Support Center) was available as a limited backup mode of communications, but apparently was not required or used.

4.1.2.5 Auditory Signals

During the event the following auditory signals were activated with no reported problems:

- annunciators
- plant evacuation
- computer alarm printout

Distinctive coding of these signals by type, audio frequency, intensity, and pulse duration satisfied human factors auditory signal coding guidelines.

4.1.2.6 Annunciator Warning System

The annunciator warning system consisted of 416 tiles on 13 panels, arranged 8 to a row in 4 rows (Figure 4.8). The system included an auditory alert that had one frequency and one intensity from a single sound source. Either the SILENCE or ACKNOWLEDGE buttons silenced the auditory alert signal.

Two separate panels contained first-out annunciator tiles for reactor and turbine trips. The first-out tile illuminated red and remained lit until cleared by a separate first-out reset button. Beyond the first-out concept, no annunciator priority system existed in the Ginna design.

Cleared alarms were not indicated except by turning off the illuminated tile. The cleared indication could not be differentiated from one in which the bulbs were burned out. An audible, cleared alarm indication would be desirable under certain circumstances at Ginna. For example, the reactor coolant system overpressure protection system nitrogen accumulator tanks must be refilled from the back panel and only when the illuminated tile on the front panel goes out is indication given that the tanks are filled.

The lettering of the legends on annunciator tiles was of several sizes and type styles and, in general, too small to be read easily. In addition, many of the tiles included additions and modifications in opaque Dynotape, which is inappropriate for transilluminated legend indicators (Figure 4.9).

The orientations of the three annunciator response pushbutton sets on the panel were inconsistent. The outermost sets of pushbuttons were grouped horizontally; the set on the center console was oriented vertically.

4.1.2.7 Controls

In general, anthropometric design of controls met human factors design guidelines. Accidental activation of critical controls was minimized through the use of key lock switches, covers, and guards. Direction of control movement was consistent throughout the control room.

Identification of different functional types of switches (e.g., spring-loaded momentary vs. latching) on some rotary controls, which appeared to be identical, was nonexistent. This condition was brought out during the review of the pressurizer power-operated relief valve (PORV) cycling. The operator indicated that both PORV rotary switches latch into the CLOSE, AUTO, or OPEN positions, but the associated block valve rotary switches located immediately to the right are spring-loaded momentary-contact switches with CLOSE and OPEN positions. The switches looked identical except for the number of indicated positions (Figure 4.10). In addition, there was no unique identification on spring-loaded momentary-contact valve control switches to inform the operator whether or not to hold the switch in the activated position until the valve completed its stroke. The task force identified no instance where operators were confused by the lack of functional identification.

4.1.2.8 Visual Displays

The visual display system at Ginna includes the full spectrum of meters, light indicators, graphic recorders, and counters.

Meters of both vertical and circular movement generally conformed to human factors guidelines in readability, scale marking, and pointer direction of movement. However, zone markings, consisting of grease pencil and tape in several colors, located on the cover glasses of many meters deviated from human factors guidelines.

The reactor coolant loop subcooling monitors used two different calibrations, one for T_{HOT} above 500°F and one for T_{HOT} below 500°F. This condition resulted in a display on a single vertical meter of actual subcooling when T_{HOT} was above 500°F, and one-half actual subcooling when T_{HOT} was below 500°F. Operators were reminded of this calibration logic by a small sign below these meters; but operators had to be aware of actual T_{HOT} to correctly interpret these readings. The T_{HOT} parameter was only available on a computer printout. During the tube rupture event, at least one licensed operator did not correctly interpret these meter readings and reported one-half actual subcooling values when the information was requested.

Light indicators, both legend and nonlegend, have a multitude of applications in the Ginna control room. During the review, it was noted that bulbs were burned out on both legend and nonlegend indicators. Since most nonlegend lights use a single bulb, the indication was not available when the bulb was burned out. Administrative controls on the replacement of burned-out bulbs were either weak or were not adhered to as evidenced by the large number of bulbs which had to be replaced as a result of this review.

Color appeared to have had multiple meanings, a source of potential confusion. For example, red was identified as having the following meanings: open valve, closed breaker, high radiation, instrumentation on the A instrument power bus, and first out annunciators.

Status legend lights had very small lettering which was not easily readable. In addition, not all the bulbs were equally bright; the legend lights with dimmer bulbs were difficult to read. Apparently, the light intensity of bulbs was related to age.

With one exception, graphic recorders met human factors design guidelines. The small Foxboro type used in several applications on the front panel could not be read easily and did not feed paper smoothly. One of these, the wide-range reactor coolant system pressure recorder was the primary indication used during cycling of the PORV.

Both drum-type and electronic counters used in the Ginna control room appeared to meet human factors guidelines for their applications.

4.1.2.9 Labels and Location Aids

There was no hierarchical labeling scheme in the control room except for a few subsystem titles on groups of displays. Labels were generally placed below displays and above controls, but there were many exceptions. In general, the size of type was smaller than human factors design guidelines recommend for readability. Component titles and numbers and control position identifiers were all of equal size. The use of terms and abbreviations was inconsistent. For example, it was observed that steam generator appeared as STEAM GEN, STM GEN, and S/G. In addition, terminology appearing on the panels was inconsistent with that appearing in procedures (See Section 4.3.3.2.8).

There was extensive use of temporary (Dynotape) labeling throughout the control room.

There was no use of location aids, such as system or functional demarcation or system flow mimics (Figure 4.3).

4.1.2.10 Process Computer

The process computer used at Ginna was a Westinghouse PRODAC 250. The console in the control room consisted of a function keyboard and three printout typewriters. The keyboard permitted the operator to select the format and specify the characteristics of such things as trend tables to be printed out on the trend typewriter. The alarm typewriter printed most alarms, but not all, and not necessarily in time sequence when several occurred in close order. In addition, the time indicated on the alarm printer was the print time, not the event time. The typewriter speed was approximately 30 lines per minute. Alarms were printed in bold type; cleared alarms and other information appeared in medium type. The log typewriter printed selected plant parameters on an hourly basis.

The computer was out of service for approximately 16 min during the event. Since the computer printout was being used to monitor core subcooling during this time, the operators were required to perform the calculations manually, using the incore thermocouple monitor and steam tables.

4.1.2.11 Panel Layout

Primary control was on the main control console, and systems appeared to have logical groupings. Layouts were reasonably consistent and standardized, and only one case of mirror imaging was found on a back panel. Controls were sufficiently separated to minimize interference or inadvertent actuation. In several instances, strings of displays and clusters of controls exceeded the number recommended by human factors guidelines.

4.1.2.12 Control and Display Integration

The desired vertical alignment of control, display, and annunicator appeared to be maintained on the primary control console in most instances. One notable exception surfaced during the review of the PORV cycling operation during this event. The narrow-range pressurizer pressure indicator was located close to the PORV valve control. However, since the pressurizer pressure was already offscale of the narrow-range indicator, it was necessary to use the wide-range reactor coolant system pressure recorder to monitor pressure drop while cycling the valves. This recorder was located approximately 6 ft to the left of the control location (Figure 4.11) and could not be read by the operator cycling the valve. Since the PORV is not a throttle valve, the rate of pressure drop could not be controlled. Thus the operator had someone else read the pressure aloud while the operator opened and closed the valve. The inherent lag time in a two-person operation of this type, when the cycling times are in seconds, made the task difficult and forced the "bump-and-wait" type of operation that occurred.

4.1.3 Technical Support Center

4.1.3.1 General Layout

The Technical Support Center shown in Figure 4.12 was located at ground level adjacent to the Turbine Building. It consisted of one large main room surrounded by a series of offices and supporting facilities. The main room was approximately 30 by 40 ft. Applicable supporting facilities included a technical library, conference room, computer room, communications facility, emergency power facilities, the Westinghouse Technical Representative's office, kitchen, and lavatory facilities. The NRC Resident Inspector's office was also located in the Technical Support Center.

4.1.3.2 Emergency Coordinator Work Station

The Emergency Coordinator's table was equipped with a 20-button telephone. It also contained a set of site contingency procedures, the emergency operations facility and control room manning and communications diagrams, a corporate phone book, and speed memo blanks. The emergency coordination organization chart was located on the wall behind the desk (Figure 4.13). As individuals assumed their functional responsibilities, each placed his or her magnetized name tag on the chart at the appropriate function label.

4.1.3.3 Plant Assessment

The plant assessment table was similarly equipped with two 20-button telephones. The Plant Assessment Manager sat at the head of the table, the Technical Assessment Manager and Team occupied one side, and the Maintenance and Operations Manager and Team occupied the other side.

A direct-line, sound-powered, battery-assisted phone with a headset was also available for backup communication to the control room. Directly behind the Technical Assessment Manager were the conference room and technical library.

The conference room was used for Plant Operational Review Committee (PORC) meetings. The technical library contained technical manuals, procedures, a stick file of drawings, and emergency and other equipment. An envelope for each manager, containing all necessary documents, was also stored in the technical library.

4.1.3.4 Health Physics and Chemistry Assessment and Dose Assessment

The Health Physics and Chemistry Assessment and Dose Assessment Managers and their supporting teams occupied a third table equipped with two 20-button telephones, a XETEX 501A Radiation Monitor, and appropriate procedures. Behind the desk on large map boards were the site maps, dose projection map, and individual survey team maps.

One wall of the Technical Support Center contained three large white boards on which were kept plant status, meteorological and survey team status, and other information deemed useful to the group. In addition, graphs of major plant parameters versus time were kept on part of the same wall near the technical library.

4.1.3.5 Communications

The communications area included the switchboard which handled all incoming and outgoing phone calls, except for direct-line calls, such as Emergency Notification System, Health Physics Notification System, State/County, Emergency Operations Facility and corporate calls. The communications area also contained a telecopier and a single-frequency FM radio for fire, security, Survey Team, and maintenance information.

4.1.3.6 Security

The Security Manager's desk was equipped with a straight-line phone and a Motorola Siren Actuation Indicator.

4.2 Personnel Responses

4.2.1 Operations

Before the steam generator tube ruptured, the plant was operating at normal operating temperatures and pressures for 100% steady-state power. At 9:25 a.m., all four pressurizer low-pressure alarms were annunciated. Almost simultaneous alarms included:

- charging pump speed alarm
- steam generator B level deviation alarm
- steam generator B steam-flow/feed-flow mismatch alarm
- condenser air ejector radiation monitor (R-15) alarm
- pressurizer level deviation alarm
- pressurizer pressure deviation alarm.

At approximately 1.5 min into the event, the Shift Supervisor ordered the Control Operator to reduce turbine load using the turbine manual fast rate control.

At approximately the same time, the following alarms were indicated:

- the reactor coolant system low pressure
- overtemperature ΔT
- containment fan coolers service water discharge radiation (R-16)
- steam dump armed

The Head Control Operator's first action was to increase the speed of the charging pump (which was in manual operation) to maximum (one pump was in automatic control) and to start the third charging pump. The operators did not initiate either a manual reactor trip or a safety injection actuation, because they were unsure of the cause for existing plant conditions and were confident that if conditions did degrade, the automatic reactor trip or safety injection actuation, or both, would occur.

Following the automatic safety injection actuation, the operators tripped the reactor coolant pumps as directed by established criteria in the emergency procedures. Before tripping the reactor coolant pumps, the operators had concluded that the event was a steam generator tube rupture, probably in the B steam generator. The basis for this conclusion was: increasing pressure and level in the B steam generator, steam-flow/feed-flow mismatch, and R-15 alarm. After tripping the reactor coolant pumps, the operators observed that natural circulation was taking place, as indicated by the subcooling monitor, reactor ΔT, and incore thermocouples.

Within 5 min after the first set of alarms was received in the control room, the Shift Technical Advisor began to read aloud to the operators the plant emergency procedures for a loss of coolant accident and a steam generator tube rupture. He continued to follow the course of the event and the actions taken by the operators to ensure the steps specified in these procedures were carried out.

At 9:33 a.m., the Shift Supervisor notified NRC Headquarters of the tube rupture event using the Emergency Notification System from his office. The Shift Supervisor remained on line for approximately 1 min responding to questions from the NRC duty officer. The telephone was then manned, and information requested by NRC was provided by various personnel other than the operating shift. The Emergency Notification System line remained open until 4:00 p.m. on January 26. According to shift personnel the communications with NRC did not interfere with their duties during this event.

At 9:40 a.m., the Plant Superintendent declared an Alert.

The operators confirmed that the B steam generator had experienced tube rupture by taking portable radiation meter readings of the main steam line. The operators then secured all steam supplies from and feedwater supplies to the B steam generator.

At 9:53 a.m., the B steam generator PORV was isolated by shutting the upstream isolation valve; this action was initiated to prevent release to the atmosphere at the PORV pressure setpoint of 1060 psig. (This action did not prevent atmospheric relief through the ASME Code safety valves once pressure increased to this setpoint. Further, this action removed the option of relieving the B steam generaotr pressure through a path which had a block valve.) At 9:55 a.m., the B steam generator narrow-range level indication went off-scale high, although all feedwater had been previously secured.

At approximately 9:57 a.m., the safety injection signal was reset. The reset was performed after the requirements for reset were met, as specified in Procedure E-1.4, Revision 10. Resetting the safety injection allowed the operators to reset containment isolation and regain instrument air inside containment; the latter was required for control of air-operated valves within the containment. At 10:04 a.m. one charging pump was restarted, although the steam generator tube rupture procedure required the starting of all three charging pumps. With a charging pump in operation, the pressurizer auxiliary spray was available for control of pressurizer pressure, but the auxiliary spray valve was not used because the plant's Technical Specifications preclude using the spray if a ΔT of greater than 320°F exists between the source of the spray and the pressurizer.

During the period 10:07 to 10:09 a.m., the pressurizer PORV was manually cycled to reduce reactor coolant system pressure. The separation of the wide-range reactor coolant system pressure indication from the PORV controls required another non-shift person to tell the Head Control Operator what effects opening the PORV had on system pressure. The two-person operation was the primary reason for not maintaining the PORV in the open position for a longer period. While closing after the fourth opening, the PORV motion stopped in an intermediate position, and then the valve reopened. The operators quickly shut the PORV block valve.

At 10:09 a.m., operators recognized that a steam bubble had formed in the reactor vessel head because the rapid increase of pressurizer level could not be attributed to the makeup to the reactor coolant system provided by the charging and safety injection pumps. Reactor vessel head thermocouples located in the head water space were used by operators to confirm that steam formation conditions existed.

At 10:17 a.m., an auxiliary feedwater pump was started and intermittently operated to maintain water level in the A steam generator.

At 10:11 a.m., an operator shut the block valve for the second pressurizer PORV because the elevated PORV tailpipe temperature appeared to indicate that leakage existed.

At 10:19 a.m., a decrease in B steam generator pressure and the subsequent noise heard by the control room personnel indicated that an ASME Code safety valve had lifted.

The requirements for securing the safety injection pumps as specified in Procedure E-1.4, Revision 10, were met at approximately 10:10 a.m. Continued running of the pumps deviated from Procedure E-1.4 and resulted in increasing the B steam generator pressure until the lift pressure of the safety valve was reached. The delay in securing the safety injection pumps was caused by the plant staff's concern about core cooling conditions that might result from securing the pumps and by a need to check parameters further to ensure that securing the pumps would be a prudent action.

At 10:37 a.m., safety injection was secured, and NRC was informed of this occurrence. NRC Region I asked the plant staff to justify securing safety injection and discussed this matter further with the Plant Superintendent over the Emergency Notification System.

At 10:40 a.m., the condensate pumps were secured to prevent further radioactive contamination of the condensate full-flow demineralizers. This action caused the turbine condenser to be unavailable for dumping of steam from the A steam generator with the condenser steam dump valves. Operators throttled open the A steam generator atmospheric PORV to continue the cooldown. Also, at about this time, pressurizer heaters were energized to reestablish the steam bubble in the pressurizer.

At 10:44 a.m., the Plant Superintendent acting as the Emergency Coordinator declared a Site Emergency.

At 10:52 a.m., the rupture disc on the pressurizer relief tank burst.

At about 11:07 a.m., a safety injection pump was restarted to provide pressure control during the planned restart of a reactor coolant pump. The manual discharge valve of the safety injection pump was throttled to three-fourths closed prior to starting and was subsequently throttled to the seven-eighths closed position. Starting a safety injection pump at this time was not a requirement of the steam generator tube rupture procedure.

The A reactor coolant pump was restarted at 11:21 a.m. The PORC had made an assessment of plant conditions and determined that it was necessary to restart a reactor coolant pump to collapse the bubble in the reactor vessel head and aid in bringing the plant to a stable condition in a controlled manner. The delay between starting the safety injection pump and starting the reactor coolant pump was the time required by the plant staff to assess the possible consequences of a reactor coolant pump start. The steam generator tube rupture procedure could not be sequentially followed because pressurizer pressure and level control had not been reestablished, a condition required by procedure for reactor coolant pump restart.

At approximately 11:25 a.m., NRC was notified that the control room ventilation system had been manually shifted to the recirculation mode by placing the associated area monitor in the source-check condition, and that the pressurizer control and backup heaters were energized.

At 11:52 a.m., the pressurizer level indication showed that a steam bubble was being reestablished in the pressurizer. The steam bubble was being formed by heating the pressurizer with the pressurizer heaters.

At approximately 12:00 noon, normal charging, letdown, and pressurizer pressure control had been established. The reactor coolant system was being cooled by forced circulation and dumping steam to the atmosphere through the A steam generator PORV.

The operating staff's major objectives for the remainder of the event were to: cool down the reactor coolant system and steam generators; degas and purify the reactor coolant system; and downgrade the event from a Site Area Emergency to an Alert and then to the Recovery phase. The initial rate of cooldown was slower than normal because of the licensee's desire to minimize the potential for a "water hammer" effect in the flooded B steam line, which the plant staff thought might occur as the B steam generator pressure decreased to saturation conditions for the water trapped in its steam line. To further mitigate the consequences of a water hammer occurrence, the plant staff decided to pin the steamline hangers outside containment. At lower reactor coolant system temperatures and corresponding A steam generator pressures, the cooldown rate was limited by the amount of steam which could be relieved through the A steam generator PORV.

The Emergency Coordinator downgraded the event at 7:17 p.m., to an Alert condition.

The residual heat removal system was put into operation at approximately 7:00 a.m. on January 26, 1982. The A reactor coolant pump remained in operation to degassify and purify the reactor coolant system. The Alert was downgraded to the Recovery phase at 10:45 a.m.

4.2.2 Personnel Interview Highlights

Task Force interviews with shift personnel and other plant staff who were on duty during the event produced the following results:

(1) Shift personnel understood the objectives of the steam generator tube rupture procedure. The licensed operators had received simulator training on the steam generator tube rupture event. The simulators responded in a similar manner to the course of this event, but at a slower rate.

(2) Shift personnel and other plant staff stated that the Shift Supervisor maintained control of the actions taken to mitigate the event.

(3) At peak manning of the control room, approximately 15 persons were present. The Shift Supervisor stated that the presence of these people did not interfere with his duties.

(4) The Shift Supervisor stated that the normal shift staff was adequate to cope with the event had it occurred on a backshift. He further stated that he would have had some difficulty performing the functions of the Emergency Coordinator, other than sounding the evacuation alarm and initiating the call list.

(5) The Shift Supervisor and the Auxiliary Operators stated that the Auxiliary Operators, on their own initiative, checked safeguards equipment in their areas for proper operation following the initiation of safety injection.

(6) Step 3.9.3 of Procedure E-1.4 states, "Put the atmosphere steam dump valve in the manual closed position." Other steps in the procedure ensure that all steam supplies from the faulted steam generator are isolated. The operators stated that they interpreted this to mean manual isolation of the atmosphere steam dump valve with the block valve, instead of placing the valve controller in the manual and shut position.

(7) Consideration was not given to verifying that the pressurizer PORV block valve was operable before operating the PORV.

(8) Plant personnel indicated that had an accurate reactor vessel water level indicator been in operation, it would have aided in understanding and stabilizing plant conditions during this event.

(9) Shift personnel stated that they were aware that the "feed-and-bleed" process (auxiliary feedwater leakage into the reactor coolant system via the tube break) was diluting the reactor coolant system boron concentration and slightly reducing the shutdown margin. They knew the boron concentration required to maintain a 2% reactivity shutdown margin was about 700 ppm. The minimum concentration reached during the 48 hours following the start of event was 1858 ppm boron.

(10) Shift personnel and other plant staff stated that they did not deviate from applicable procedures. (See Section 4.3.4 for NRC Task Force identified deviations.)

(11) Shift personnel and other plant staff interviewed stated that the repressurization thermal shock issue is not a concern for the Ginna reactor vessel, given the existing shutoff head of the safety injection pumps. They further indicated that this issue is not addressed in the plant's Emergency Operating Procedures.

(12) Shift personnel and other plant staff stated that there are no Ginna procedures in regard to mitigating the consequences of simultaneous tube leaks in both steam generators, and there has been minimal training in

this area. There was no consensus relative to actions that should be taken to mitigate such an event.

(13) Shift personnel and other plant staff stated that the postulated event in which a relief or safety valve sticks open on the steam generator that has experienced a ruptured tube is not addressed in plant emergency procedures. The consensus indicated that the pressurizer PORV would be opened to permit cooling the core with safety injection and to maintain an inventory of water in the containment for subsequent cooling to prevent the core from becoming uncovered.

4.2.3 Technical Support Functions

4.2.3.1 Plant Superintendent Functions

During a site emergency such as the steam generator tube rupture event, the Plant Superintendent has a twofold responsibility: he maintains his role as Plant Superintendent, but he also functions in the role of Emergency Coordinator when the Technical Support Center is activated. In both functions he also presides as Chairman of the Plant Operations Review Committee meetings.

4.2.3.1.1 Plant Superintendent Activities

When he was notified about a safety injection, reactor trip, and air ejector radiation monitor alarm by telephone from the control room, the Plant Superintendent told his staff, which had been assembled for a routine Monday morning staff meeting, and he then proceeded to the control room. After verifying that the event was indeed a steam generator tube rupture and ensuring that the control room staff was handling its responsibilities properly, he checked the status of the radiation emergency procedure and determined that the plant was indeed in an Alert status. After ensuring that the declaration of the Alert was announced, he proceeded to the Technical Support Center at approximately 9:40 a.m. The Plant Assessment Manager was already activating the Technical Support Center organization, and manning had begun. At 9:46 a.m., the Plant

Superintendent notified designated authorities in New York State, Monroe County, and Wayne County. He noted that the Technical Support Center was fully manned and operational at 9:58 a.m. The Plant Superintendent then notified the control room that he was assuming responsibility as Emergency Coordinator.

4.2.3.1.2 Emergency Coordinator Activities

The Emergency Coordinator is responsible for the conducting of the site contingency procedure, in this case SC-1. The Emergency Coordinator maintained phone communications with the Emergency Operations Facility and direct communications with the various assessment groups while the Assistant Station Superintendent monitored accomplishment of the steps of the site contingency procedure. When it was clear to the Emergency Coordinator that the plant had experienced a large primary-to-secondary leak event, the faulty steam generator safety valve was reducing pressure as designed, a radioactive release was in progress, and degraded fuel conditions did not exist, he conferred with the Technical Support Center staff and declared a Site Area Emergency at 10:44 a.m.

The Emergency Coordinator directed the Operating Engineer to remain in the control room rather than report to the Technical Support Center as the emergency plan implementing procedure specifies. This action was one suggested improvement to the procedures that was recognized after the emergency preparedness exercise conducted on January 21, 1982.

Most technical discussions and interaction with the control room were handled by the Plant Assessment Manager and Technical Assessment group. When recommendations were ready, they were discussed with the Emergency Coordinator for his approval, and then sent to the control room. One exception to the process occurred in the decision to terminate safety injection. The subject was being discussed in the Technical Support Center when the Operations Engineer in the control room contacted the Emergency Coordinator to advise him that safety injection was going to be terminated. The Emergency Coordinator asked the

Operations Engineer to wait, checked with the Technical Assessment group for potential disagreement, and, when there was none, passed the concurrence to the Operations Engineer.

Throughout the early part of this event, the Emergency Coordinator used his Assistant Station Superintendent to verify that steps in the procedures were indeed accomplished, that proper information was transmitted to all applicable parties, and that proper notification forms were being used to record control room data for the state and county. At approximately 11:00 p.m. on January 25, the Assistant Station Superintendent relieved the Plant Superintendent as Emergency Coordinator until approximately 8:00 a.m. January 26, when the Plant Superintendent returned.

4.2.3.2 Plant Assessment Functions

The Plant Assessment functions include Technical Assessment, Operations Assessment, Maintenance Assessment, and Health Physics and Chemistry Assessment.

Part of the Plant Assessment function included communications with the Emergency Operations Facility and the Engineering Department at the licensee's corporate office building in Rochester, New York. Contact was also made with Westinghouse and with the Prairie Island Nuclear Station, the latter having experienced a similar event in 1979.

Disciplines represented within the Technical Assessment function were nuclear engineering, instrumentation and control engineering, electrical engineering, mechanical and hydraulic engineering, and computer systems. Operations Assessment involved the direction and coordination of operations personnel by monitoring their activities and comparing them with applicable procedures.

Dynamic technical data were obtained in the Technical Support Center from two major sources: the process computer through a computer data link and voice communications with control room personnel. The computer was out of service for approximately 16 min beginning at 11:19 a.m. on January 25. The source of technical data during that period was voice communications with control room personnel. In order to keep the operators free to perform their control tasks, phone communication was accomplished between an Assistant Training Coordinator in the control room and the Training Coordinator in the Technical Support Center. This phone line was also the primary source of operational information being monitored in the Technical Support Center by individuals using the emergency procedures. Many discussions were held in the Technical Assessment area concerning meeting criteria for certain procedural steps.

Assessment in the Health Physics and Chemistry area included monitoring activity in the primary system, predicting and monitoring activity in the secondary system as a result of the rupture, and determining boron concentrations in the reactor coolant system.

Maintenance Assessment dealt primarily with the determination of the manpower available should the need arise to perform emergency maintenance activities. One maintenance activity conducted by direction of the Technical Support Center included the pinning of the B steam generator steamline hangers when the lines were thought to be filled with water. Pinning was desired to minimize the potential of overstressing the spring hangers.

4.2.3.3 Plant Operations Review Committee

4.2.3.3.1 Quorum

The required Plant Operations Review Committee quorum consists of a Chairman and four members, including alternates.

The members present in the Technical Support Center on January 25 were the following:

Plant Superintendent (Chairman)
Assistant Plant Superintendent
Technical Engineer

Instrument and Control Supervisor
Nuclear Engineer
Results and Test Supervisor
Supervisor Chemistry and Health Physics
Maintenance Engineer

4.2.3.3.2 Mode of Operation

Since all committee members were located in the Technical Support Center, except the Operations Engineer, meetings were convened whenever the need arose. Many group discussions, other than meetings, were held during the day of the event. The Technical Support Center staff used a tape recorder for capturing the results of the meetings and other general discussions during the event. The tapes indicated that the meetings addressed at least the following significant items:

(1) limiting plant cooldown to prevent water hammer in the water-filled steam line for the B steam generator

(2) the need for the corporate engineering staff to determine the impact of dead weight water loading on the steamline pipe hangers

(3) the need to pin the steamline supports

(4) the method to be used to cool the B steam generator, including limits on parameters for the feed-and-bleed process

(5) the implication of the feed-and-bleed process on waste inventories

(6) the criteria to be used and the frequency to demonstrate adequate shutdown margin boron concentrations during the feed-and-bleed process

(7) the criteria to be used for placing the residual heat removal system into operation

[redacted]

(8) justification for deescalation from the alert phase to the recovery phase.

Other activities of lesser significance were also addressed by the PORC.

4.3 Procedures

This section discusses the procedures used by the plant staff to respond to the steam generator tube rupture and to successfully cool the plant down to the temperature at which the normal plant cooldown procedure was invoked using the residual heat removal shutdown cooling system. It also briefly discusses procedure adequacy, format, and clarity; procedural deviations; and plant staff reasons for these and their consequences. It does not cover the emergency plan implementing procedures. A brief comparison of the Ginna steam generator tube rupture procedure with the technical guideline generated for coping with it by the Westinghouse Owners' Group is also provided.

4.3.1 Procedures Used To Cope With the Event

The procedures used by the plant operating staff to cope with the event were the following:

(1) "Immediate Action and Diagnostics for Spurious Actuation of SI, LOCA, Loss of Secondary Coolant and Steam Generator Tube Rupture" (E-1.1, Revision 20)

(2) "Steam Generator Tube Rupture" (E-1.4, Revision 10)

(3) "Natural Circulation in the RCS" (0-8, Revision 2)

(4) "Void Formation in the RCS" (E-1.5, Revision 9)

(5) "Reactor Coolant Pump Operation" (S-2.1, Revision 11)

(6) "Plant Shutdown From Hot Shutdown to Cold Shutdown Condition" (0-2.2, Revision 45)

On first indications of the event, the operators followed procedural guidance from memory and permitted automatic action to take place. The head control operator increased charging flow to 100% and subsequently tripped the reactor coolant pumps at the approximate time and pressure prescribed by Ginna procedures. These initial actions were performed without the emergency procedures in hand. In the period approximately 5 min after first indications, the Shift Technical Advisor had Ginna Procedures E-1.1 and E-1.4 out and began to read them aloud to the operators. Procedure E-1.1 was used first as it was the procedure that specifies immediate operator actions on actuation of safety injection. It also specified subsequent operator actions that cover diagnostics of the event and directed the operator to the specific applicable procedure for existing symptoms and plant conditions. In this case, the appropriate procedure, E-1, Step 3.3, called for the operator to go to E-1.4, "Steam Generator Tube Rupture."

Procedure E-1.4 was the guiding procedure for the remainder of the event. However, the plant staff referred to other procedures for specific actions when the need arose.

When the reactor coolant system pumps were tripped, actions specified in Plant Procedure 0-8, Revision 2, "Natural Circulation in the RCS," were performed to confirm that natural circulation had been established. Subsequently, plant parameters were checked to confirm that natural circulation was maintained. It should be noted that this procedure advises that steam voids can result during cooldown even though the 50°F minimum temperature difference between T_{SAT} and T_{HOT} is observed.

Following the depressurization and the development of the steam bubble in the reactor vessel head, Plant Procedure E-1.5, "Void Formation in the RCS," was consulted. The procedure called for determining core exit thermocouple temperature readings, and this was done repeatedly to confirm an adequate margin to saturation. This procedure was used by the operators to confirm that there was no void in the core and that natural circulation did exist. A corrective measure to recover from a voided condition (called for in Step 3.5 of Procedure E-1.5) was to start a reactor coolant pump. Although a voided core condition did not exist, the operators felt a need to start a reactor coolant pump to collapse the steam bubble under the reactor vessel head. To start the pump, Ginna Procedure S-2.1 was used. This is the normal plant operating procedure that gives initial conditions and instructions for starting and running the reactor coolant pumps.

Following restart of a reactor coolant pump, securing the safety injection pumps, restoration of charging and letdown, stabilization of the reactor coolant system pressure, and establishing pressure control in the pressurizer, cooldown was continued. Cooldown was accomplished in the reactor coolant system, and steam generator A according to Procedures E-1.4 and O-2.2, "Plant Shutdown From Hot Shutdown to Cold Shutdown Condition," by steam release through the A steam generator PORV, since the condenser had been made unavailable through earlier operator action. However, Procedure E-1.4 was silent on the technique to be used for cooldown of the faulted steam generator. Thus, an oral instruction was developed in the Technical Support Center and given to the operational staff. The strategy conveyed was to feed the steam generator up to a level of about 60% of narrow range and reduce primary side pressure by spraying the pressurizer to an indicated pressure of about 25 psi below the secondary side pressure. The secondary-side water would be allowed to flow through the tube break back into the primary side and the steam generator narrow-range level allowed to drop to a minimum of about 25% of scale. The instruction called for boron sampling at half-hour intervals to ensure no encroachment on the required shutdown margin. The feedup of steam generator level and bleed back to the primary was repeated on the order of six to eight cycles to accomplish the desired cooling.

The cooldown was accomplished in accordance with written procedures, except for the cooling of the B steam generator. The cooldown actions after the residual heat removal system was placed in service was accomplished by following Procedure O-2.2 as directed by Procedure E-1.4.

[redacted]

4.3.2 Comparison of Ginna Procedure E-1.4 With Westinghouse Owners' Group Guideline E-3, Revision 1, September 26, 1979

In this section, differences are noted between Ginna Procedure E-1.4, "Steam Generator Tube Rupture," and Westinghouse Owners' Group Emergency Instruction E-3, "Steam Generator Tube Rupture." Also noted are some similarities between Procedures E-1.4 and E-3 that influenced the course of the event.

Ginna Procedure E-1.4 tracks very closely with Guideline E-3 because it is based on an early technical version of the guideline, one without all the planned rigorous human factors treatment found in the latest revision. The basic differences were the adaptation of Guideline E-3 to the format of Ginna emergency procedures and the inclusion of plant-specific data and plant-unique equipment into Ginna's Procedure E-1.4. Some additional plant-specific procedural notes and cautions appear in Procedure E-1.4.

4.3.2.1 Procedural Key Elements

The key elements of both the procedure and the guideline dealt with the following basic procedural steps:

(1) identification of the faulted steam generator

(2) isolation of the faulted steam generator to minimize release of radioactivity to the environment

(3) rapid cooldown of the reactor coolant system to provide a margin to saturation during the subsequent depressurization

(4) depressurization of the reactor coolant system to a pressure equal to the faulted steam generator pressure to stop leakage

(5) maintenance of reactor coolant system inventory, adequate subcooling, and shutdown margin

(6) continued cooldown of the reactor coolant system and, when possible, placing the residual heat removal system in service.

4.3.2.2 Procedural Differences

Specific meaningful differences determined by the Task Force review follow:

(1) Reactor coolant pump trip criteria provided by these instructions:

E-1.4: pressurizer pressure $\leq$1715 psig, based on the lowest pressure indication available from an environmentally qualified transmitter*

E-3: steam generator safety valve set pressure plus 100 psi, plus a pressure value to compensate for measuring system uncertainties, location, and errors*

(2) The need for safety injection reset was identified in the same approximate sequential location; however, E-1.4 also required waiting for the automatic safety injection pump suction transfer from the boric acid storage tank on low level to the refueling water storage tank

(3) Instructions were provided in E-1.4 for operation of the pressurizer PORVs using the reactor coolant system overpressurization nitrogen system in the event the instrument air supply was not available

(4) A caution and note in Ginna Procedure E-1.4 included tables not in E-3 that discussed potential level indication errors in steam generators and the pressurizer because of high containment temperature and pressure

(5) Nontechnical procedural guidance was found within Ginna Procedure E-1.4. These steps required initial notification to offsite authorities and

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*Although the licensee's reactor coolant trip criterion deviated from the NRC-approved optional Westinghouse guidelines, it was consistent with NRC Bulletin 79-06C requirement to trip the pumps after a reactor trip and safety injection caused by low pressure.

update reports at specific plant parameter thresholds which were not described in E-3.

4.3.2.3 Procedural Similarities

Similarities in E-1.4 and E-3 that influenced the Ginna tube rupture event were:

(1) reactor coolant pump trip: Although the pressure values at which pumps are to be tripped were different in these instructions, both required tripping at a reduced pressure indication.

(2) reactor coolant system bubble formation: Guidance was not provided in either instruction for identification of reactor coolant system bubble formation and how to cope with a bubble, although the depressurization without forced circulation specified in both instructions was conducive to bubble formation. "Cautions" in both instructions did advise that pressurizer water level indication should always be used in conjunction with other specified reactor coolant system indications to evaluate system conditions and to initiate manual operator actions. (It should be noted that, as discussed in Section 4.4.1, Ginna has a procedure "Void Formation in the RCS." Procedure E-1.4 does not refer the operators to this procedure. Entry conditions for use of this procedure did not directly apply to the Ginna tube rupture event.)

(3) securing safety injection pumps: Specific conditions were included in both instructions for securing the safety injection pumps; i.e., 200 psi increase after verifying closure of PORV and return to an onscale pressurizer level indication (20% at Ginna). The instructions stated "stop all operating safety injection pumps" when these conditions are met. Both instructions failed to discuss a bubble in the reactor coolant system and what to do with the safety injection pumps under this condition. Neither E-1.4 nor E-3 Revision 1 specified a subcooling criterion for terminating safety injection pump operation, although later revisions of E-3 do.

(4) reactor coolant pumps restarting: Restarting a reactor coolant pump was specified in both instructions in the same approximate sequential order. This appeared after reactor coolant system depressurization to the pressure of the faulted steam generator and after the safety injection pumps were secured.

4.3.3 Adequacy of Pertinent Ginna Procedures Used for Responding to the Steam Generator Tube Rupture

Plant procedures served to minimize on-the-spot analysis and decisions for many of the plant responses. Some problems were identified.

4.3.3.1 Immediate Action and Diagnostics for Spurious Actuation of Safety Injection, a Loss-of-Coolant Accident, Loss of Secondary Coolant, and Steam Generator Tube Rupture (Procedure E-1.1, Revision 20)

Procedure E-1.1, in general, specified necessary actions to respond to plant symptoms to ensure that the important safety functions were carried out; i.e., reactivity was controlled, adequate coolant inventory was maintained, a decay heat removal path was established, and containment isolation was verified. Subsequent operator actions provided steps to diagnose the cause and to direct the operators to the appropriate emergency procedure, e.g., "Loss of Secondary Coolant" or "Loss of Reactor Coolant." Many diagnostic actions were specified in the procedure to guide operator actions when a plant experiences an automatic actuation of safety injection. The procedure was used only briefly, since it was apparent early in the event that the plant had suffered a steam generator tube rupture.

This procedure required that all reactor coolant pumps be stopped after safety injection pump operation was confirmed and when pressurizer pressure was 1715 psig. This action is required for all events that lead to rapid depressurization and safety injection. For the circumstances of this event, tripping of the reactor coolant pumps stopped forced circulation into the head region of the vessel and adversely affected its cooldown.

The following observations were made by the Task Force during review of Procedure E-1.1:

(1) Step 1.1.7 identified high steam generator blowdown radiation as a symptom of tube rupture. This symptom occurred 25 min into the event, and about 20 min after the event was identified as a steam generator tube rupture.

(2) Step 2.2.7 stated that service water pump start indication relies on "sufficient" pressure. "Sufficient" was undefined.

(3) Step 3.2 cautioned the operator to maintain seal injection flow when the reactor coolant pumps were stopped. The operator could not comply with this step until the safety injection and containment isolation were reset.

4.3.3.2 Steam Generator Tube Rupture (Procedure E-1.4)

The basic elements for coping with the rupture were contained in Procedure E-1.4. The symptoms and immediate operator actions for this event were not included in the body of this procedure; instead it referred to E-1.1, which was used in conjunction with this procedure in the immediate action and diagnostic phases of the event. Automatic actions were identified under Section 1.0, "Symptoms," in E-1.1. Thus, these two procedures were complementary for coping with a rupture.

The mission of the steam generator tube rupture procedure is rapid cooldown and depressurization of the reactor coolant system to the pressure of the faulted steam generator. The hot reactor vessel head region exceeded the saturation temperature for the reduced pressure and caused the formation of steam in the vessel head region. This situation occurred at Ginna but did not in itself interfere with core cooling during the event. Because the pressurizer was full and a bubble existed under the vessel head, the operators lacked information regarding the actual primary system inventory. The operators frequently verified that core exit temperatures were subcooled and were confident that the core was being adequately cooled. The operators were unsure of the effect of the terminating safety injection.

Observations made by the Task Force during review of Procedure E-1.4 are discussed below.

4.3.3.2.1 Bubble Formation

Neither Procedure E-1.1 nor E-1.4 provided information regarding bubble formation or its consequences for operating equipment in coping with a rupture; for example, safety injection pump shutdown and restart of an reactor coolant pump.

4.3.3.2.2 Reactor Coolant Pump Trip Criterion

The reactor coolant pump trip criterion was established by the licensee at $\geq$ 1715 psig based on the lowest pressure indication available in the control room from an environmentally qualified pressure transmitter. Other pressure indications were available, but they did not have certified environmental qualifications; however, a steam generator tube rupture does not create a hostile environment for these transmitters. The pump trip pressure criterion was higher than that specified in the Westinghouse Owners' Group guidelines (Section 4.3.2). A lower pressure trip allows pumps to remain operating for a range of small ruptures.

4.3.3.2.3 Effects of Containment Temperature on Pressurizer and Steam Generator Level Indications

The event did not create high temperature and pressure in the containment. Thus, discussion of steam generator and pressurizer vessel level indications under various containment temperatures was not needed.

4.3.3.2.4 Operation and Shutdown of Safety Injection Pumps

Procedure E-1.4 addressed the automatic start and restart of the safety injection pumps. The procedure also provided criteria for shutdown of the pumps; i.e., reactor coolant pressure increase $\leq$200 psi and at least a 20% level indication in the pressurizer. It did not include in those criteria a subcooling margin value that must be reached before safety injection pump shutdown.

4.3.3.2.5 Actions for Cooling Faulted Steam Generator

Procedure E-1.4 is silent about how to cool the faulted steam generator. As indicated in Section 4.3.1 the plant Technical Assessment Group provided instructions on accomplishing the cooldown.

4.3.3.2.6 Restart of a Reactor Coolant Pump

This action is specified in Step 3.19, which sequentially followed safety injection pump termination, establishment of normal charging and letdown, and use of the pressurizer for pressure control. Sequentially, the step cannot be performed in accordance with procedures with a bubble in the reactor vessel and the pressurizer level off-scale high. Since the procedure did not deal with steam formation under the reactor vessel head, it did not deal with the potential consequences of a reactor coolant pump restart and the effects of a rapidly collapsing steam bubble.

4.3.3.2.7 Steam Generator Tube Rupture With Other Failures

Procedure E-1.4 and the Westinghouse guidelines did not address a steam generator tube rupture coupled with inability to isolate a stuck-open or blown-off safety or relief valve on the faulted steam generator. Such an event would open the primary side through the leak to the atmosphere and complicate core cooling. The procedure did not provide guidance on detecting a leaking safety or relief valve based on pressure indications.

4.3.3.2.8 Format and Clarity

The format of the Ginna emergency procedures did not conform to current human factors practices in some instances. A method to help the operator keep his place in the procedure was lacking. The narrative format used was sometimes lengthy. A note instead of a precaution advised operators not to use pressurizer water level alone to evaluate reactor coolant system conditions. This advice was meant to prevail for the entire procedure and should have been properly identified as such. Some clutter existed; e.g., effects of containment temperature on pressure indication. In addition the procedure terminology was not always consistent with control board terminology. For example, the procedure referred to "PORV backup isolation valve"; on the control board the valve is identified as "PRESSURIZER REL. STOP VLV."

4.3.3.3 Natural Circulation in the Reactor Coolant System (Procedure O-8)

As indicated in Section 4.4.1, Procedure O-8 was consulted to confirm existence of natural circulation. For purposes of coping with this event, no problems were identified.

4.3.3.4 Void Formation in the Reactor Coolant System (Procedure E-1.5)

This procedure did not address bubble formation at less than 700°F incore thermocouple temperature. Thus, entry conditions for using this procedure did not exist during the Ginna event. It did help the operators in the determination that the core did not contain voids. Neither this procedure nor the guidelines identified the potential for a bubble in the reactor vessel head area, how the bubble could be recognized, and how to recover full vessel level. Neither procedure directed the operators to an appropriate procedure for recovery.

4.3.3.5 Reactor Coolant Pump Operation (Procedure S-2.1) and Plant Shutdown From Hot Shutdown to Cold Shutdown Condition (Procedure O-2.2)

For this event, no problems were identified.

4.3.4 Procedure Adherence, Potential Deviations, and Consequences

Procedures are written to cover actions for coping with emergencies with the philosophy that they will be implemented by qualified operators. Nevertheless, procedures do not and cannot cover all contingencies that might arise under a faulted condition. Rather, they cover expected behavior with some contingencies for alternative failures, but always leading to a success path. Conceptually they are designed to ensure the success of maintaining important safety functions.

When actions are covered in procedures, the prescribed actions must be followed. When the event deviates from expectations, a reasoned and considered approach to cope with the contingency should be developed. It is expected that the method developed will be presented to management and authorization for the prescribed actions will be obtained, unless immediate action is required to protect the health and safety of the public.

Operator compliance with procedural steps for coping with this event were, in general, good. The emergency procedures covering this event were used early in the event and, in general, followed step by step.

The actions that deviated from approved steam generator tube rupture Procedure E-1.4, Revision 10, were the following:

(1) Starting one charging pump in preparation for reactor coolant system to B steam generator pressure equalization, instead of starting all charging pumps, as discussed in the procedure (Step 3.11). The reason for this deviation was not determined.

(2) After meeting the criteria for securing the safety injection pumps, plant staff delayed this action. A review of plant parameters had demonstrated adequate core cooling and natural circulation. The plant staff was unsure of the consequences of securing the safety injection pumps, but recognized that continued operation would lead to B steam generator safety valve lifts. Safety injection pumps were subsequently secured and monitored plant parameters demonstrated continued core cooling.

(3) Securing the condensate pumps which made the turbine condenser unavailable for the condenser steam dumps (Step 3.20). The condensate

pumps were secured to prevent further contamination of the condensate full-flow demineralizers with radioactive water.

(4) Restarting of a safety injection pump as a prerequisite for starting a reactor coolant pump was not discussed in Procedure E-1.4, but it was done because normal pressurizer pressure control had not been reestablished and the plant staff was uncertain about the type and magnitude of the pressure transient which would occur during the starting of a reactor coolant pump. The operating safety injection pump caused two subsequent lifts of the B steam generator safety valve.

The Task Force identified only one other example of deviations from procedures. During the initial stages of the event, the Plant Superintendent directed the Operations Engineer to remain in the control room instead of reporting to the Technical Support Center as required by the site's Emergency Plan Implementing Procedures. This decision was based on a planned procedural improvement developed as a result of a recent drill.

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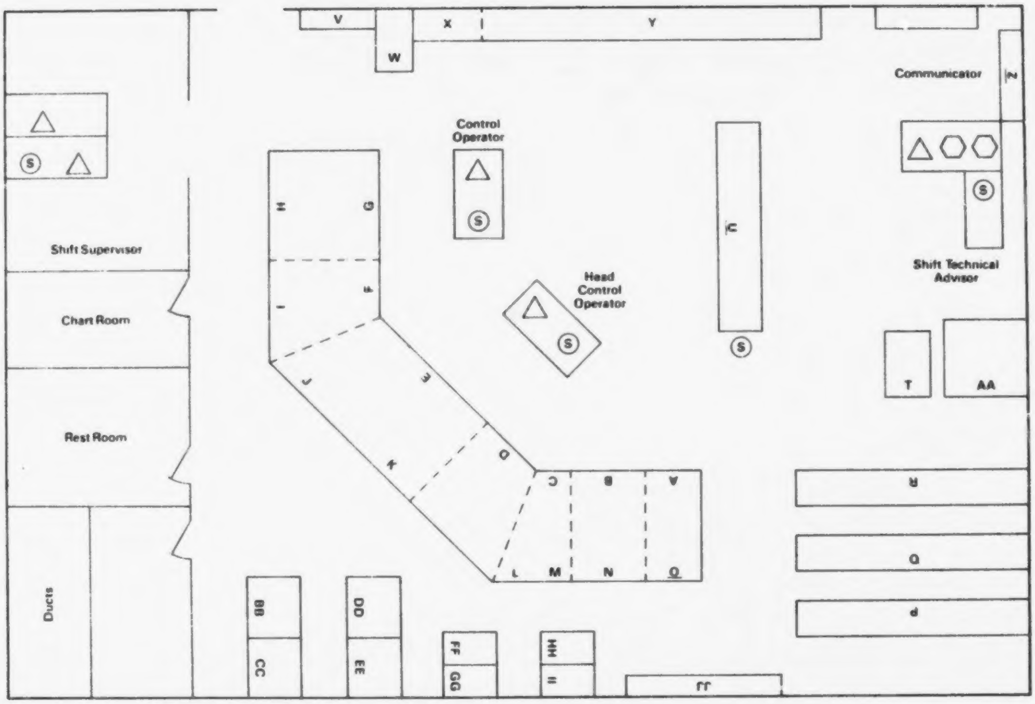
V
X
Y
W
Communicator
Z
Control Operator
Shift Supervisor
Chart Room
Rest Room
Ducts
H
G
I
F
J
E
K
D
Head Control Operator
U
Shift Technical Advisor
T
AA
C
B
A
L
M
N
O
R
Q
P
BB
CC
DD
EE
FF
GG
HH
II
JJ

A - Chemical Volume and Control System
B - Engineered Safety Features
C - Rod Control
D - Primary Coolant Control
E - Secondary Coolant Control
F - Turbine Control
G - Electrical Distribution
H - Electrical Bus Breakers
I - Electrical Relays
J - Secondary Plant Alarms
K - Temperature Monitors
L - Standby Auxiliary Feedwater
M - Auxiliary Building and Containment Ventilation
N - Diesel Generators
O - Safety Injection Accumulators, Power Operated Relief Valves
P - Excore Nuclear Instrumentation
Q - Incore Flux Mapping, Incore Thermocouples Readout
R - Radiation Monitors, Weather Data
T - Containment and Auxiliary Ventilation Radiation Monitors

U - Operator Console - Prodac 250 Computer
V - Fire Protection Monitor
W - Base Radio Communications
X - Fire Protection Control
Y - Switchyard Control
Z - Procedures Storage
AA - Containment Isolation Status, Temperature Saturation Monitors, Pressurize Safety Valves Positions
BB - Reactor Protection I (Red)
CC - Reactor Protection II (White)
DD - Reactor Protection III (Yellow)
EE - Reactor Protection IV (Blue)
FF - Rod Speed Control
GG - Steam Dump
HH - Pressurizer Pressure and Level
II - Rod Insertion Limits
JJ - Instrument Bus Distribution

Communications: Ⓢ Straight-Line Telephone Sets
⬡ ENS, State-County Lines
△ 20-Button ECTS

Figure 4.1 Control room

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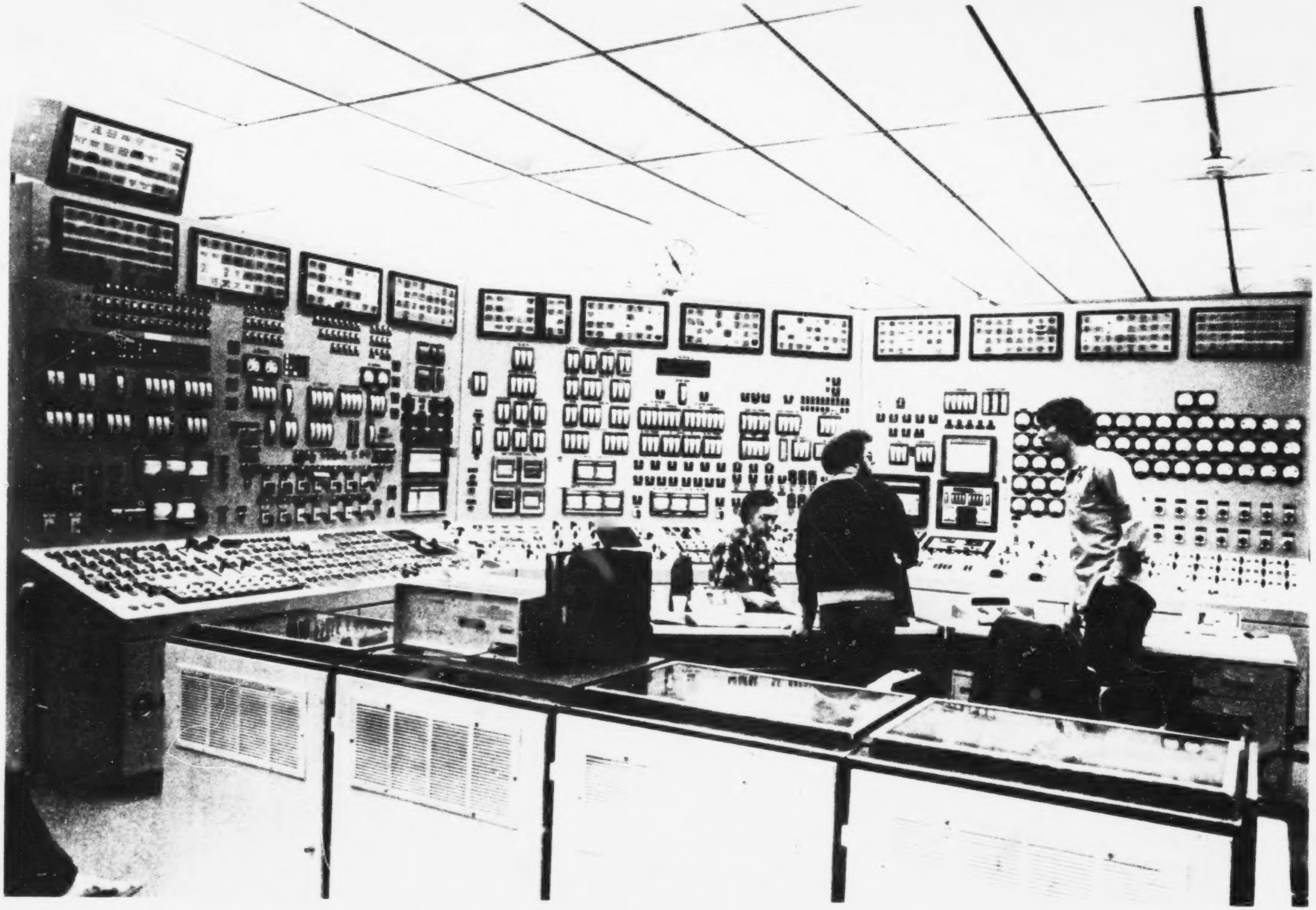

Figure 4.2 Primary operating area

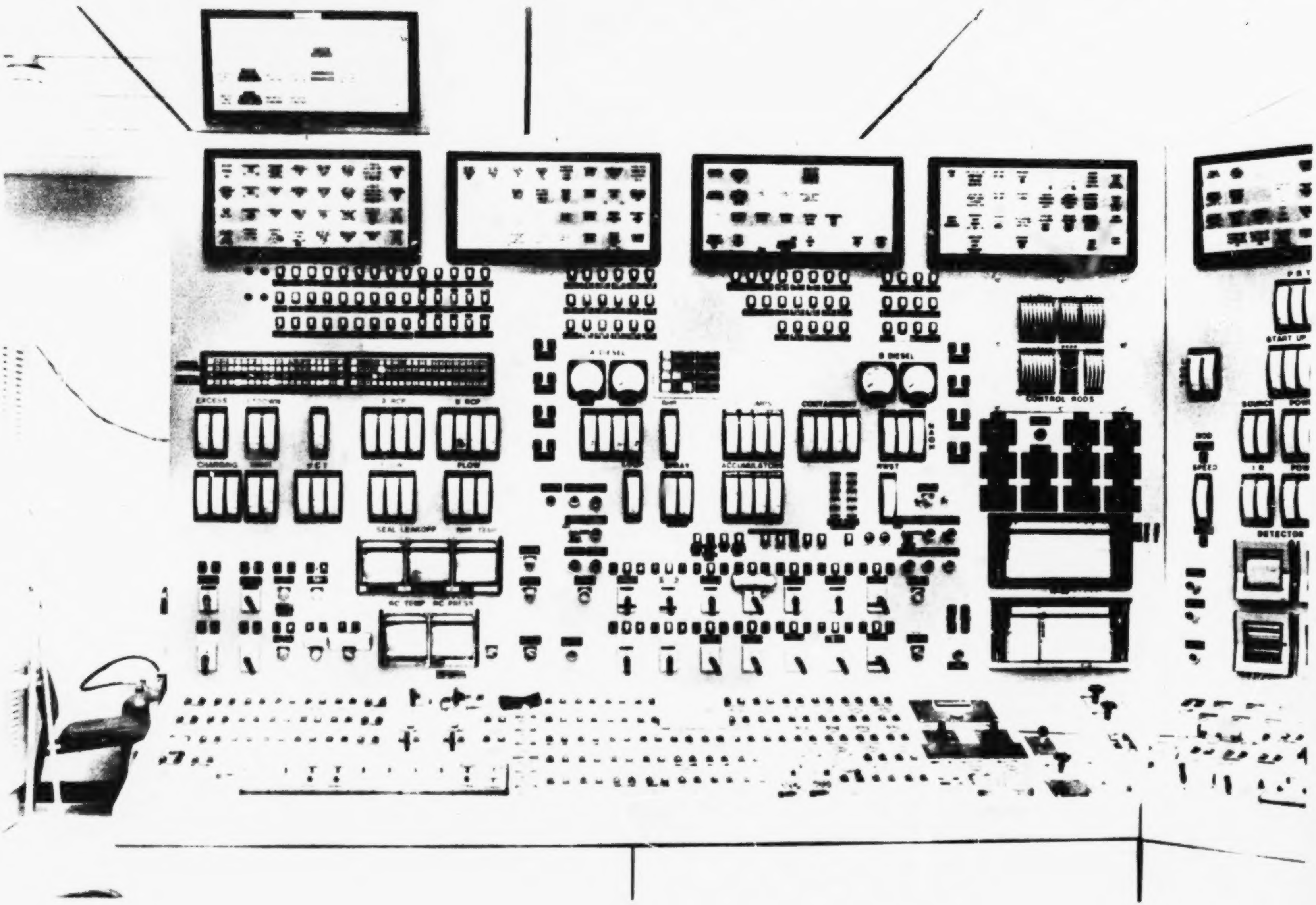
EXCESS
A RCP
B RCP
CHARGING
FLOW
SEAL LEAKOFF
RC TEMP
RC PRESS
A DIESEL
B DIESEL
SPRAY
CONTAINMENT
ACCUMULATORS
CONTROL RODS
START UP
SOURCE
SPEED
DETECTOR

Figure 4.3 Standup console, left wing

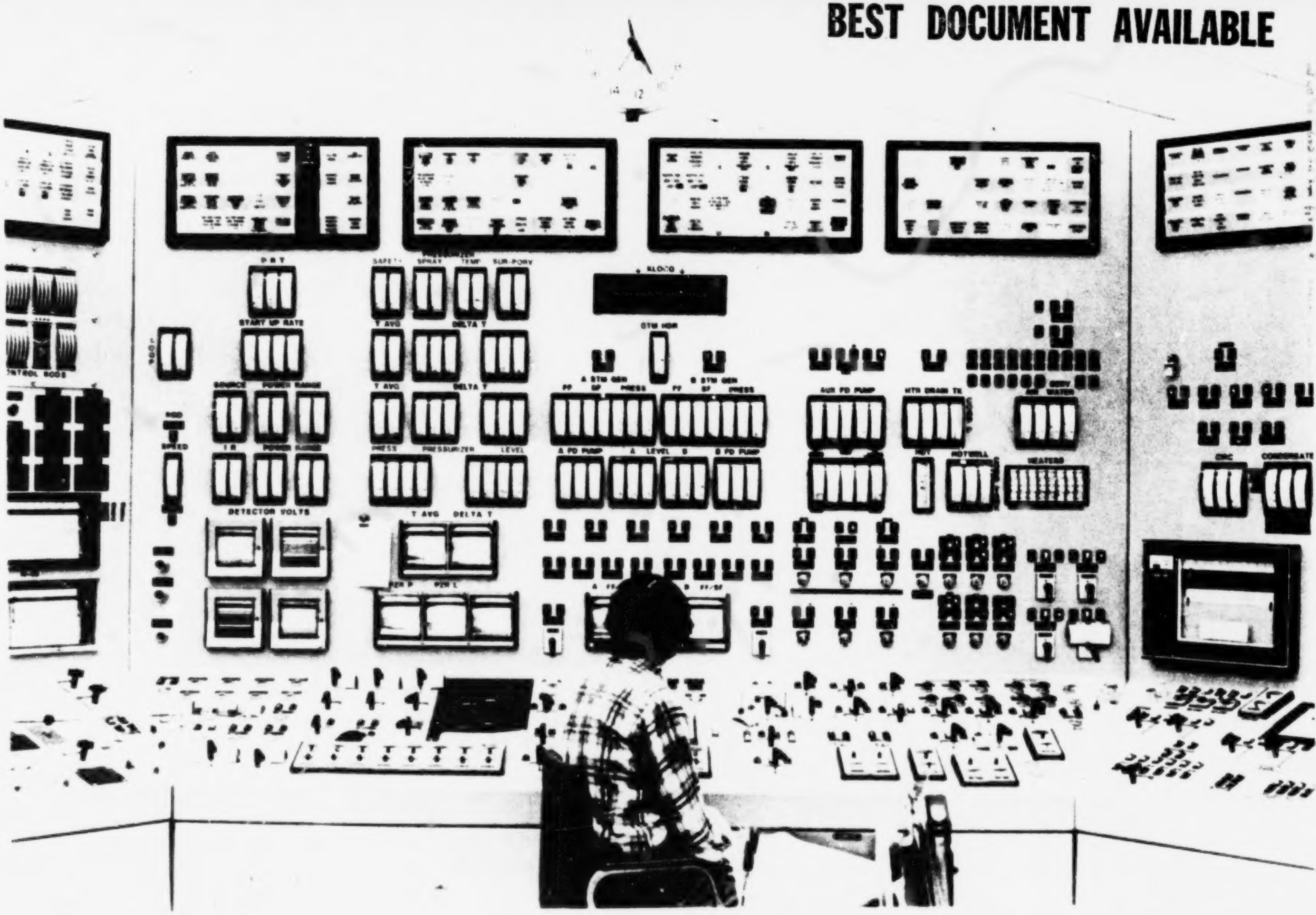
PRT
SAFETY
SPRAY
PRESSURIZER
TEMP
SUR-PORV
START UP RATE
T AVG
DELTA T
STM HDR
A STM GEN
B STM GEN
SOURCE
POWER RANGE
PRESS
I R
PRESSURIZER
LEVEL
A FD PUMP
A LEVEL B
B FD PUMP
AUX FD PUMP
HTR DRAIN TK
HOTWELL
HEATERS
CIRC
CONDENSATE
DETECTOR VOLTS
T AVG
DELTA T
SPEED
ROD
CONTROL RODS

Figure 4.4 Standup console, center

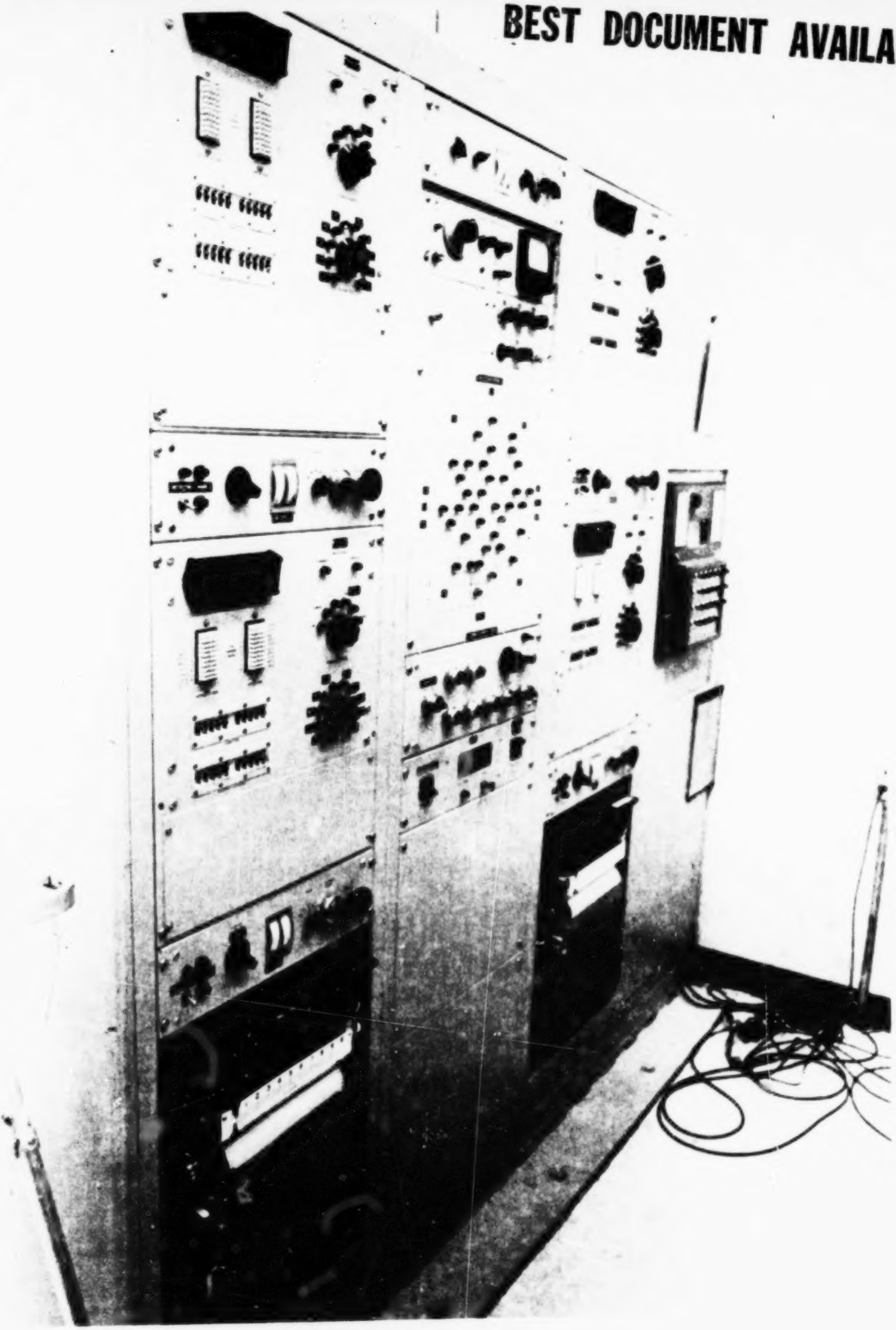

Figure 4.5 Incore flux mapping, incore thermocouples

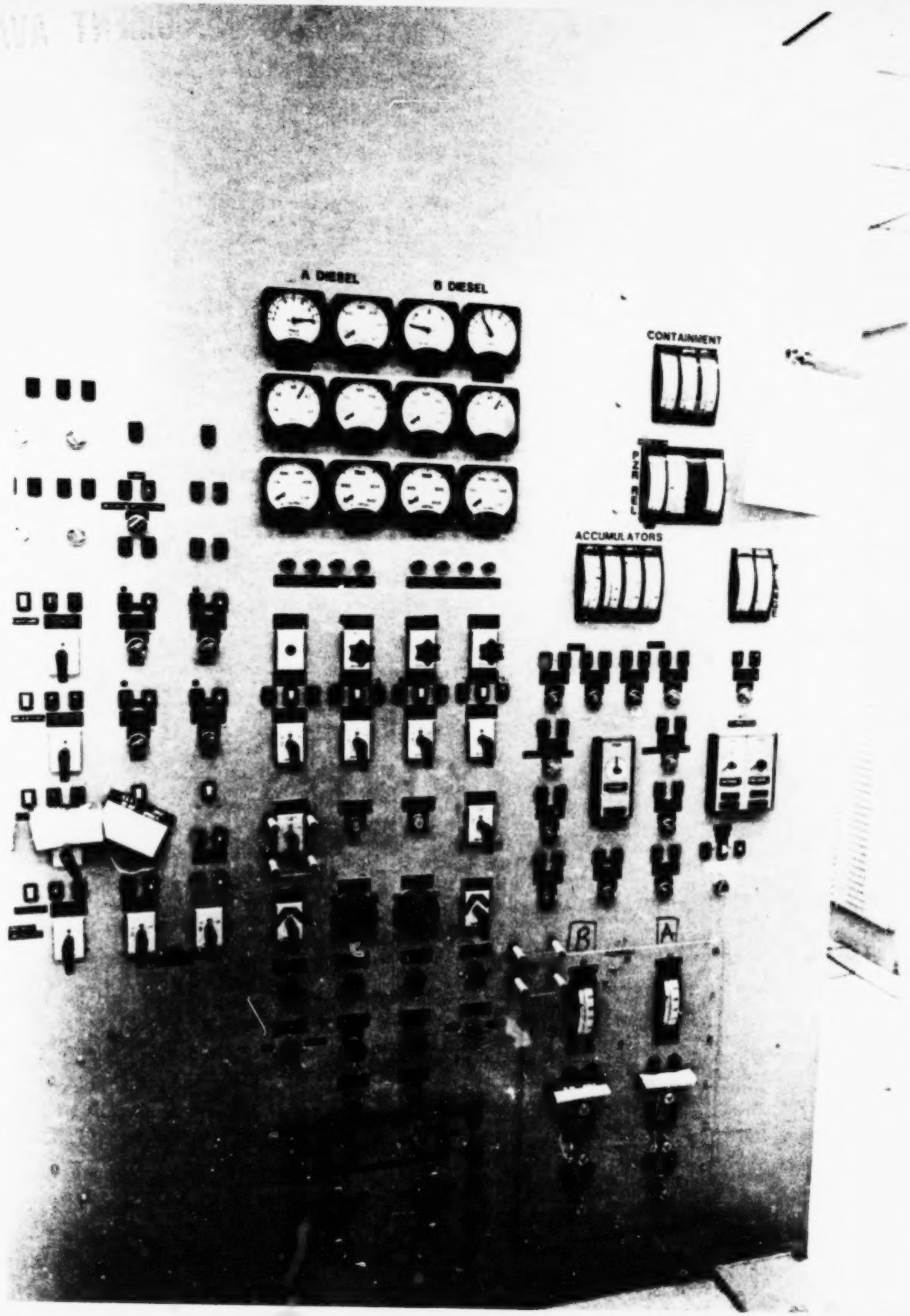
A DIESEL
B DIESEL
CONTAINMENT
ACCUMULATORS
B
A

Figure 4.6 Control panel showing diesel generators, pressurizer power-operated relief valves, and safety injection accumulators

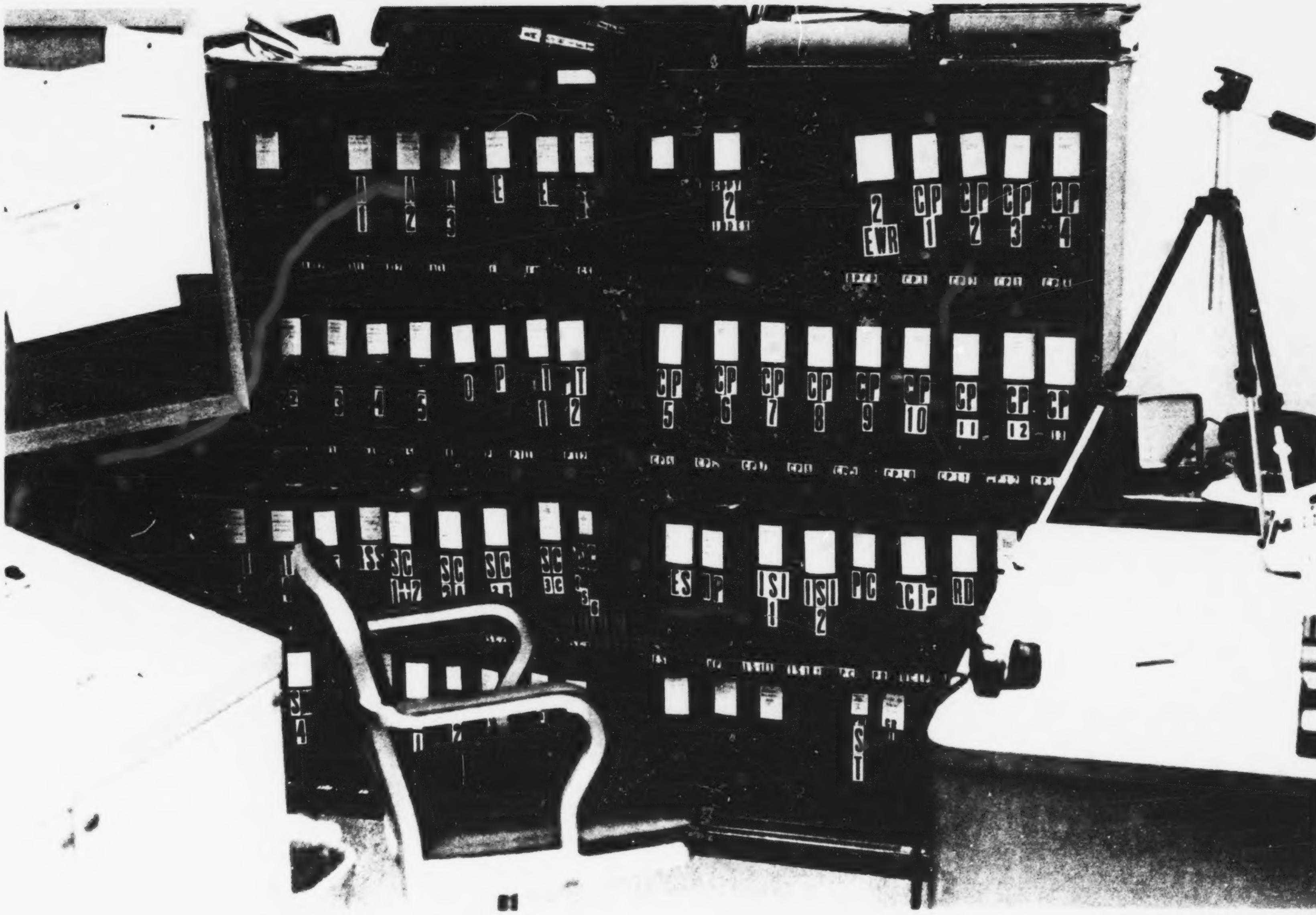
2
EWR
CP 1
CP 2
CP 3
CP 4
CP 5
CP 6
CP 7
CP 8
CP 9
CP 10
CP 11
CP 12
ES
ISI 1
ISI 2
PC
CIP
RD
ST

Figure 4.7 Operating procedures storage

C

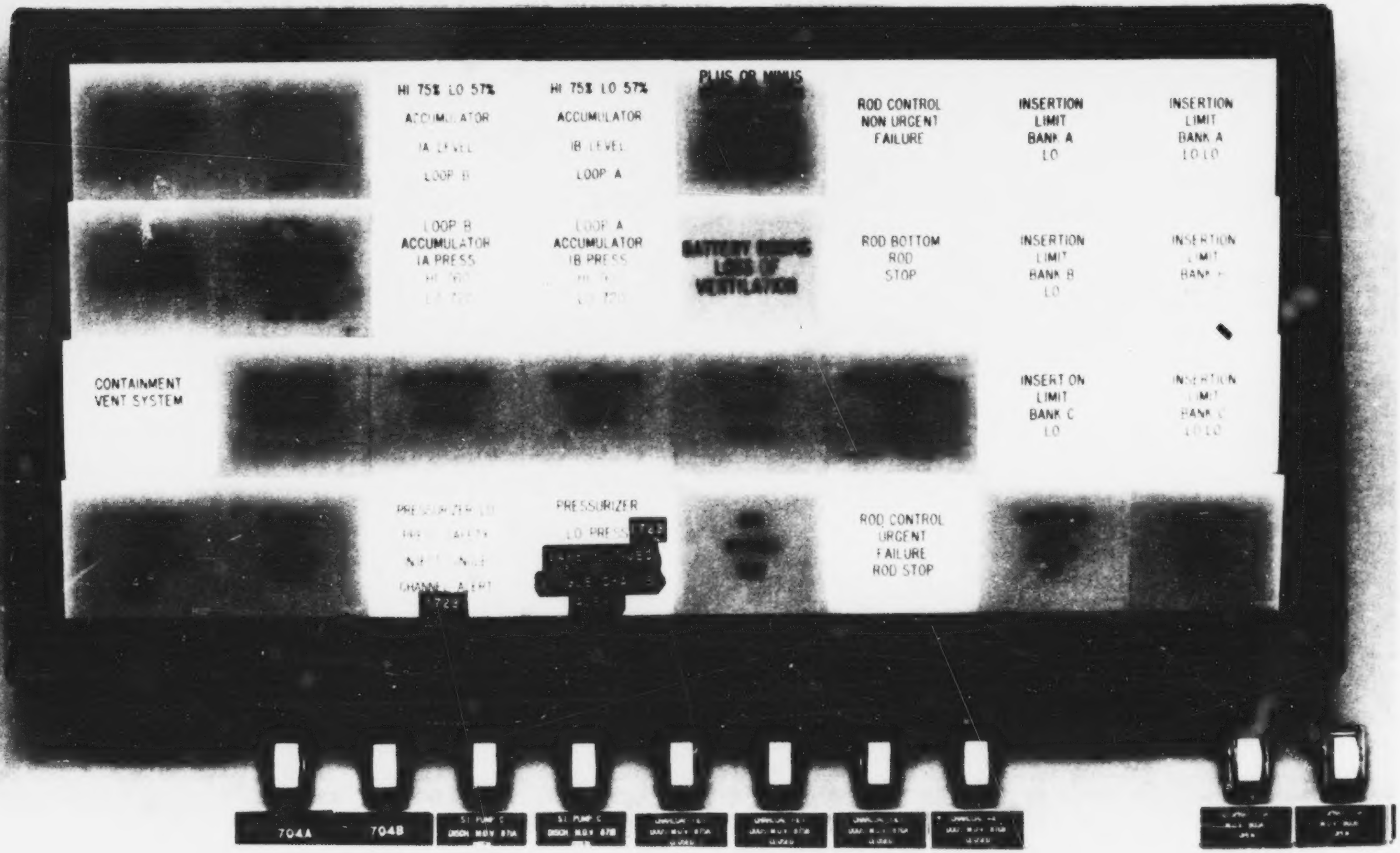
HI 75% LO 57%
ACCUMULATOR
IA LEVEL
LOOP B
HI 75% LO 57%
ACCUMULATOR
IB LEVEL
LOOP A
PLUS OR MINUS
ROD CONTROL
NON URGENT
FAILURE
INSERTION
LIMIT
BANK A
LO
INSERTION
LIMIT
BANK A
LO LO
LOOP B
ACCUMULATOR
IA PRESS
LOOP A
ACCUMULATOR
IB PRESS
LO 720
BATTERY ROOMS
LOSS OF
VENTILATION
ROD BOTTOM
ROD
STOP
INSERTION
LIMIT
BANK B
LO
INSERTION
LIMIT
BANK
CONTAINMENT
VENT SYSTEM
INSERTION
LIMIT
BANK C
LO
INSERTION
LIMIT
BANK C
LO LO
PRESSURIZER LO
CHANNEL ALERT
PRESSURIZER
LO PRESS
ROD CONTROL
URGENT
FAILURE
ROD STOP
704A
704B
SI PUMP C
DISCH MOV 878A
SI PUMP C
DISCH MOV 878B

Figure 4.8 Annunciator panel

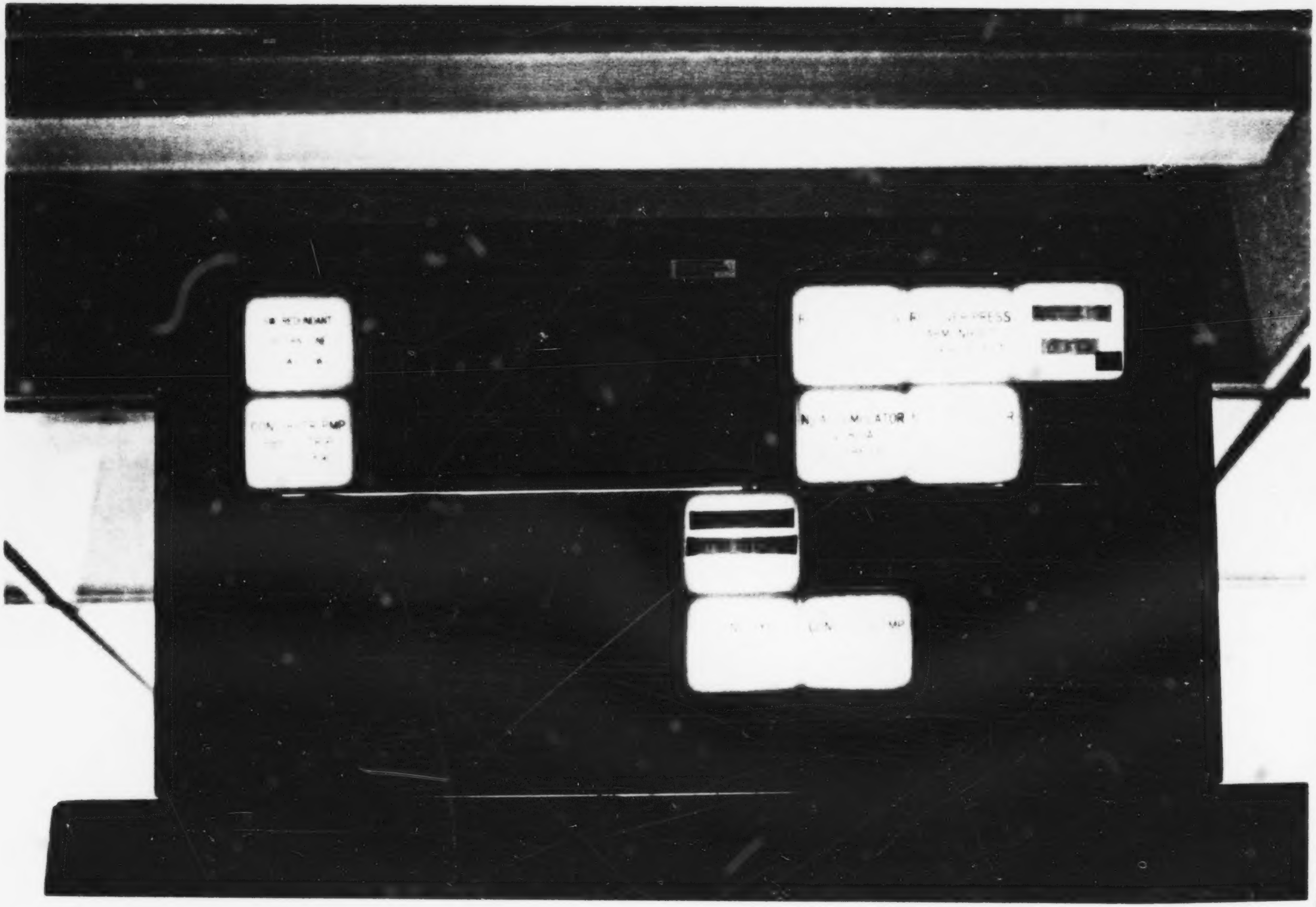
REDUNDANT
ACCUMULATOR
PRESS

Figure 4.9 Opaque labels on transilluminated legend lights

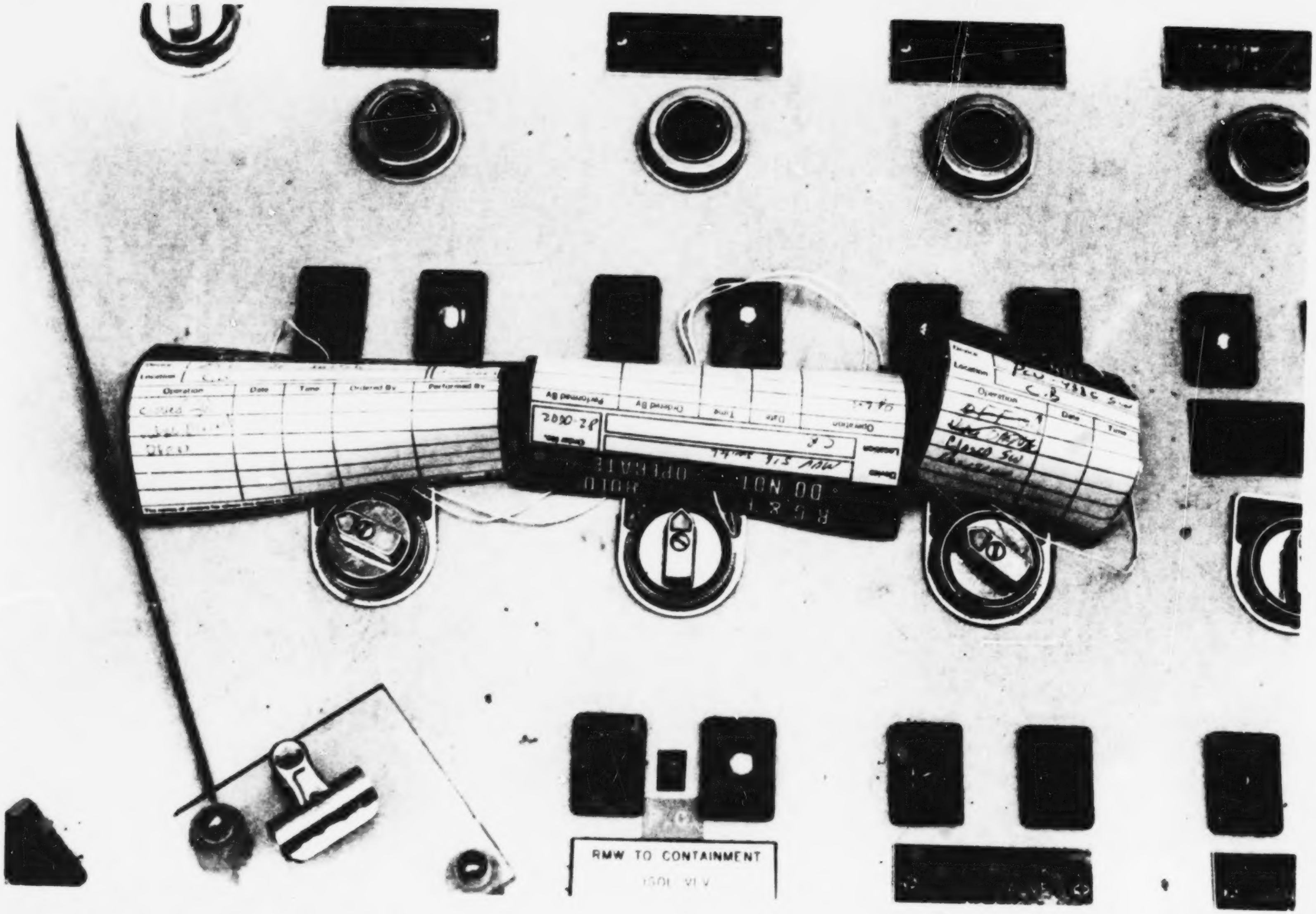
DO NOT OPERATE
HOLD
RMW TO CONTAINMENT
ISOL VLV

Figure 4.10 Power-operated relief and block valve switches

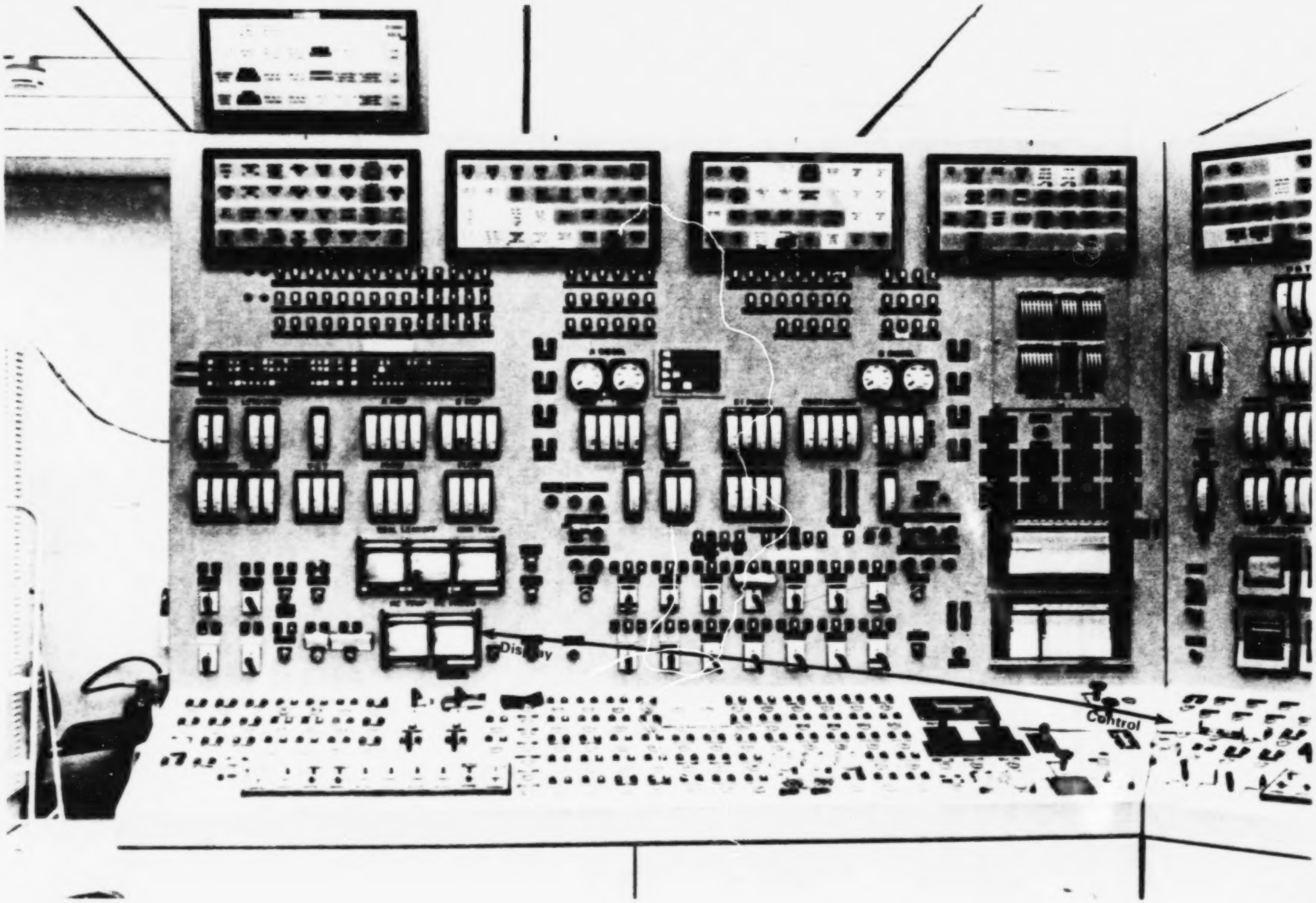
Display
Control

Figure 4.11 Power operated relief valve control and display relationship

155

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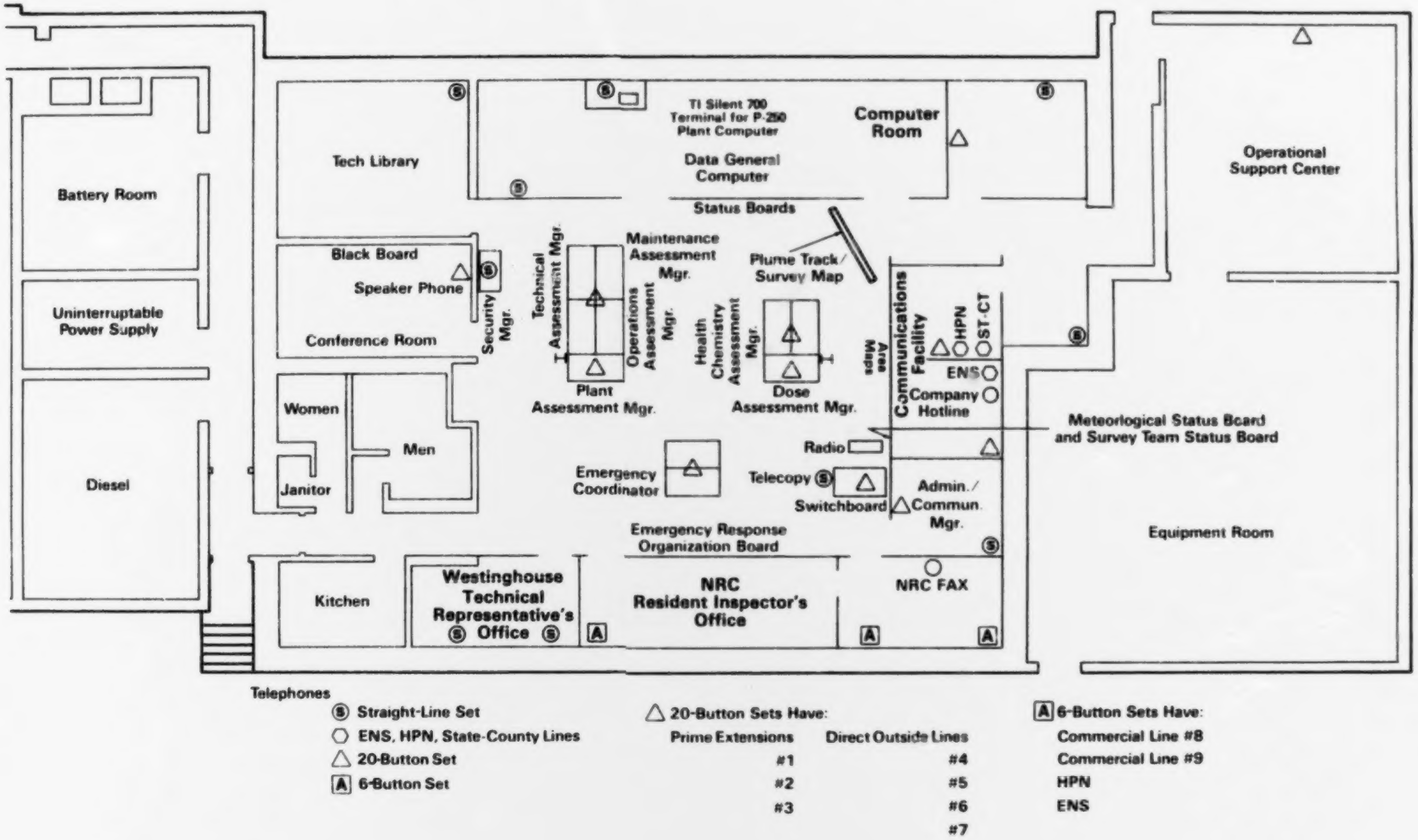
Battery Room
Uninterruptable Power Supply
Diesel
Tech Library
Black Board
Speaker Phone
Conference Room
Security Mgr.
Women
Men
Janitor
Kitchen
TI Silent 700 Terminal for P-250 Plant Computer
Data General Computer
Computer Room
Status Boards
Technical Assessment Mgr.
Maintenance Assessment Mgr.
Operations Assessment Mgr.
Plant Assessment Mgr.
Health Chemistry Assessment Mgr.
Dose Assessment Mgr.
Plume Track/ Survey Map
Area Maps
Communications Facility
HPN
ST-CT
ENS
Company Hotline
Radio
Telecopy
Switchboard
Emergency Coordinator
Admin./ Commun. Mgr.
Emergency Response Organization Board
Westinghouse Technical Representative's Office
NRC Resident Inspector's Office
NRC FAX
Operational Support Center
Meteorological Status Board and Survey Team Status Board
Equipment Room
Telephones
Ⓢ Straight-Line Set
○ ENS, HPN, State-County Lines
△ 20-Button Set
A 6-Button Set
△ 20-Button Sets Have:
Prime Extensions
#1
#2
#3
Direct Outside Lines
#4
#5
#6
#7
A 6-Button Sets Have:
Commercial Line #8
Commercial Line #9
HPN
ENS

Figure 4.12 Technical and Operational Support Center

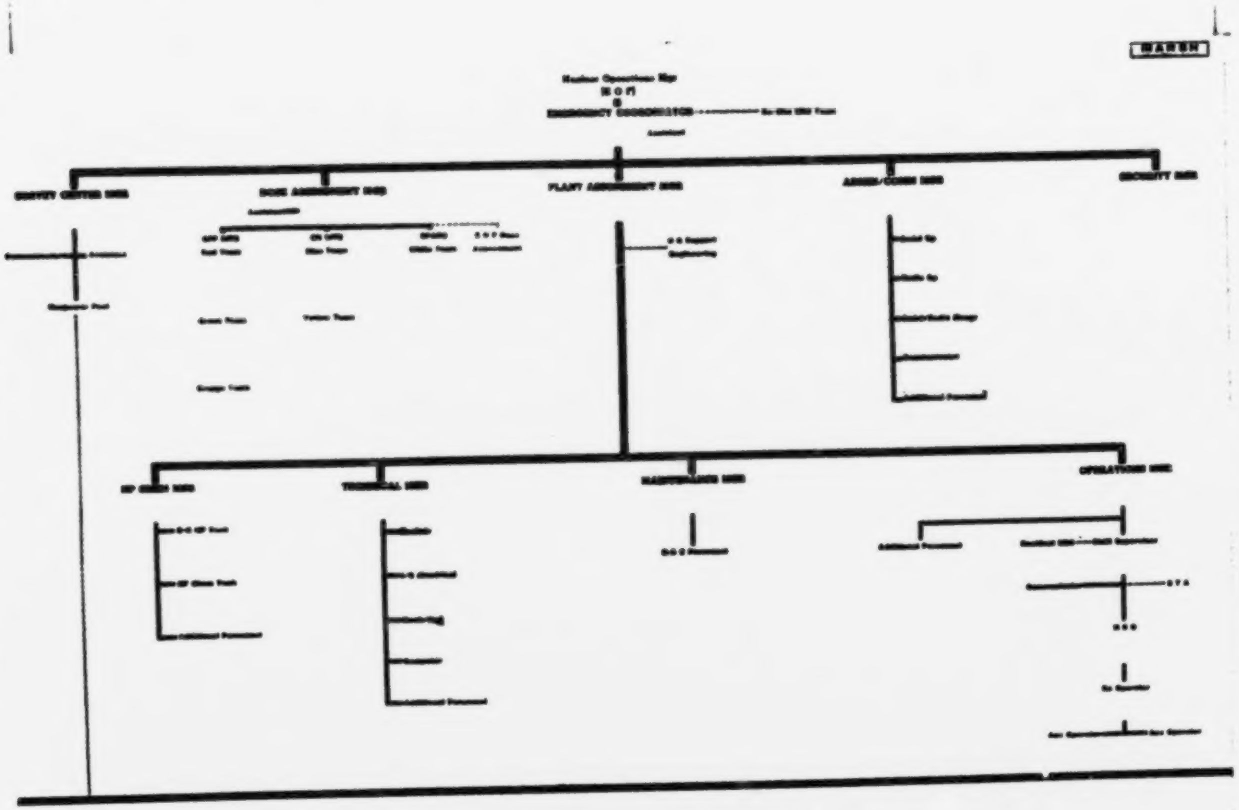

Figure 4.13 Emergency coordination organization

5 RADIOLOGICAL CONSEQUENCES

5.1 Introduction

This chapter evaluates the radiological impact of the Ginna event on people onsite and on those within a 50-mile radius of the site.

5.2 Meteorology

The release of radioactive gaseous effluent from the Ginna facility started at about 9:25 a.m. on January 25. At that time, a large-scale meteorological pattern established the weather conditions at the site. A large frontal area was present along the Gulf Coast with an intense high-pressure area in the central United States, resulting in a very strong on-shore air flow along the entire south shore of Lake Ontario, including the Ginna area. Typically for the area at that time of year, snow was falling along the south shore of the lake because of the flow of cold moist air resulting from the long overwater path. This on-shore flow condition persisted for most of the event at Ginna. Meteorological data were available at the Ginna site from a 250-foot tower located northwest of the main plant building, and from a 33-foot tower located about 0.5 mile due south of the 250-foot tower (See Table 5.1 and Figures 5.1 - 5.3.)

During the release and between 9:00 a.m. and 3:00 p.m. on January 25, the atmospheric stability indicated relatively good diffusion conditions (i.e., a neutral condition or D stability, based upon measured temperature difference between the 33 and the 150-ft tower levels).

Based upon cloud cover, wind speed and time of day, D stability would also be the resulting atmospheric stability condition during the course of the event (Slade). Table 5.1 summarizes the onsite atmospheric dispersion parameters measured from 9:00 a.m. to 3:00 p.m. on January 25.

Table 5.1 Summary of atmospheric dispersion parameters measured during the event (hourly averages)

Time-1/25/82	Wind Direction* From the:	Wind Speed,* meters/sec	Sector Affected	Atmospheric Stability
9:00-10:00 a.m.	NW	6 (~ 13.5 mph)	SE	D
10:00-11:00 a.m.	NW	6	SE	D
11:00-Noon	NW	6	SE	D
Noon-1:00 p.m.	WNW	>6	ESE	D
1:00-2:00 p.m.	WNW	>6	ESE	D
2:00-3:00 p.m.	WNW	>6	ESE	D

*Measured at the 33-ft level of the 250-ft weather tower.

An estimate of the dilution of the atmospheric releases as a function of distance from the Ginna facility was made, utilizing the centerline Gaussian equation:

$$\chi/Q = \frac{1}{u\ (\pi\sigma_y\sigma_z + cA)}$$

where

χ/Q = Relative concentrations with distance, sec/m^3

u = Average hourly wind speed measured at the 33-ft level of the 250-ft weather tower, m/sec

σ_y, σ_z = Lateral and vertical plume spread as a function of atmospheric stability and distance, m (values for σ_y and σ_z were taken from Regulatory Guide 1.145)

cA = Building wake factor for Ginna, 440 m^2. The building wake factor accounts for the turbulence immediately downwind of a structure that forces an elevated release from the building to be carried to the ground very close to the structure.

These relative concentration estimates (χ/Q) were calculated for distances from 150 meters to 80,000 meters from the plant. Figure 5.4 presents a plot of these estimates for D stability and a wind speed of 6 meters per second. Since the average wind speed was greater than or equal to 6 meters per second (about 13.5 miles per hour) during the release, and higher wind speeds produce lower χ/Q values (i.e., greater dilution), use of the data in Figure 5.4 is conservative.

Several important meteorologically related conditions in effect during the release are also relevant to the radiological impact of this event. First, snow was falling throughout the release at the rate of approximately 1/4 inch per hour. Snow is an extremely efficent mechanism for removing some radioactive substances in an effluent plume (Slade). Second, the air into which the steam was being released was cold (between 11°F and 13°F) and moist (near saturation) throughout the release and should have caused steam condensation under the existing wind conditions. Also, since the wind was relatively strong (in excess of 13 mph) and the releases were from a short vent on the building roof, the condensing plume was brought down to the ground in the wake of the building, increasing onsite deposition. This "rainout" at ground level is a very efficient means for removing radioactive materials from an effluent plume. These phenomena account for the levels of radioactivity above background in snow measurements found onsite during the event. Because of the snow and the air temperature, only a small fraction of the iodines and radioactive particulate materials remained airborne beyond the site boundary.

5.3 Sources of Radioactivity and Pathways to the Environment

This section discusses the sources of radioactivity in the plant that were available for release to the environment and were significant to the event.

5.3.1 Radionuclide Concentrations in the Reactor Coolant System

The water and steam released to the environment during the Ginna event contained radionuclides from the reactor coolant system. The licensee sampled the water in the reactor coolant system several times during the week preceding the event. Average isotopic concentrations from these samples, presented in Table 5.2, were used in the source term calculations that follow. The iodine-131 (I-131) dose equivalent (DE) concentration for this average is 0.057 µCi/g, as compared with the 3.0 µCi/g DE I-131 limit set by NRC in the Ginna Technical Specifications (approximately 2% of limit). The measured total specific activity of the reactor coolant system for that week was 3.32 µCi/g, with an average beta and gamma energy per disintegration ($\bar{E}$) of 1.62 MeV, as compared with the computed limit ($84/\bar{E}$) set by Technical Specifications of 51.85 µCi/g (approximately 6% of limit).

5.3.2 Radionuclide Concentrations in the A Steam Generator

5.3.2.1 Prior to the Event

The secondary water samples from the A steam generator taken in the 24 days prior to the event showed no detectable gross activity or detectable radioiodine.

5.3.2.2 During the Event

At 4:30 p.m. January 25, the total gross activity concentration was measured to be 3.1×10^{-6} µCi/g. By 6:30 p.m. the same day, this had decreased to 1.5×10^{-6} µCi/g, and the iodine concentration was measured to be 4×10^{-7} µCi/g DE I-131. The Ginna Technical Specifications limit for iodine activity for secondary water in either steam generator during normal operation is 0.1 µCi/g DE I-131. There is no limit for total gross activity concentration in the steam generator.

5.3.3 Radionuclide Concentrations in the B Steam Generator

5.3.3.1 Prior to the Event

Several secondary water samples from the B steam generator taken in the weeks before the event showed no detectable gross activity. A sample taken on January 15 had a concentration of 9×10^{-8} µCi/g total gross activity. Three

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Table 5.2 Measured reactor coolant system radionuclide concentrations prior to the event

Radionuclide	RCS Measured Concentration, μCi/g
Noble Gases:	
Kr-85m	3.20×10^{-2}[a]
Kr-87	6.23×10^{-2}[a]
Kr-88	7.60×10^{-2}[a]
Xe-133	7.44×10^{-1}[a]
Xe-135	2.40×10^{-1}[a]
Xe-135m	8.52×10^{-2}[a]
Xe-138	2.55×10^{-1}[a]
Ar-41	9.28×10^{-2}[a]
Corrosion/Activation Products:	
H-3	1.4[d]
Cr-51	1.2×10^{-4}[b]
Mn-54	1.7×10^{-6}[b]
Co-58	3.3×10^{-4}[b]
Fe-59	2.0×10^{-6}[b]
Co-60	2.0×10^{-5}[b]
Nonvolatile Fission Products:	
Rb-88	3.9×10^{-2}[c]
Zr-95	7.4×10^{-6}[b]
Mo-99	2.3×10^{-3}[b]
I-131	1.19×10^{-2}[c]
Te-132	2.2×10^{-5}[b]
I-132	1.91×10^{-1}[c]
I-133	9.43×10^{-2}[c]
I-134	3.26×10^{-2}[c]
Cs-134	5.5×10^{-4}[b]
I-135	1.52×10^{-1}[c]
Cs-136	1.5×10^{-4}[b]
Cs-137	9.8×10^{-4}[b]
Cs-138	4.33×10^{-1}[c]
Ba-140	1.33×10^{-5}[b]

[a] Licensee's average measured concentrations of samples collected on 1/18, 1/20, 1/22, and 1/25/82; analysis performed by licensee.

[b] Sample collected 1/21/82; analyses by Science Applications, Inc.

[c] Licensee's average measured concentrations of samples collected 1/6, 1/13, and 1/20/82; analyses performed by licensee.

[d] Based on a sample taken January 19 by the licensee.

samples taken later, but prior to the tube rupture, showed no detectable radioactivity. No samples showed any detectable radioiodine.

5.3.3.2 During the Event

The licensee sampled B steam generator water at 12:30 p.m. on January 25 following the tube rupture. Results of this analysis are presented in Table 5.3 and were also used in the source term calculations that follow. The measured concentration of radioiodine nuclides represents 0.012 µCi/g, DE I-131.

Table 5.3 Measured radionuclide concentrations in B steam generator for sample at 12:30 p.m., January 25, 1982

Nuclide	Measured Concentration, µCi/g	Nuclide	Measured Concentration, µCi/g
I-131	1.96×10^{-3}	H-3	4.9×10^{-1}
I-133	2.31×10^{-2}	Co-58	1.98×10^{-3}
I-135	2.53×10^{-2}	Co-60	5.8×10^{-4}
I-132	3.85×10^{-2}	Mo-99	7.3×10^{-4}
I-134	2.19×10^{-3}	Ba-140	2.4×10^{-2}
		Cs-137	4.4×10^{-4}

Note: These were the preliminary isotopic data obtained by the licensee and were used as source terms for releases from safety valve lifts.

Several radionuclides that were measured in the reactor coolant samples were not detected in the B steam generator secondary water sample. This was expected for noble gases (because the sample was degassed), short-lived isotopes, and those found in the reactor coolant system in very small amounts. For other radionuclides, particularly Cs-134, but possibly also Cs-136, Cr-51, and Te-132, the reason they were not detected in the licensee's analysis was not determined. The Task Force estimated that while there may have been a release of some of these radionuclides, the release was very small compared with the other radionuclides released.

5.3.4 Plant Water Inventory

The Task Force calculated water loss from the reactor coolant system by balancing the mass of water in the system at the beginning of the event with best estimates of the mass of water that entered and left the system during the event. This analysis is described in Section 3.6 of this report. In summary, a total of about 300,000 lb of water flowed from the reactor coolant system to B steam generator, and a total of about 117,000 lb of water and steam were released from this steam generator to the environment.

5.4 Pathways for Airborne Releases to the Environment

This section discusses the pathways for airborne releases of radionuclides to the environment during this event. There were two major and two minor pathways for releases of radioactivity which passed through the B steam generator.

The first major pathway for the releases of noncondensible gases was through the main condenser steam jet-air ejector. The second major pathway, through which nobles gases, tritium, iodines and nonvolatile radionuclides were released, was through the several openings of a B steam generator code safety valve. The minor pathways for release of noncondensible and volatile radionuclides were through the steam-driven auxiliary feedwater pump turbine exhaust and the A steam generator atmospheric PORV. Figure 5.5 shows the significant transport paths through B steam generator for airborne releases of radionuclides to the environment during this event.

5.4.1 Release of Noncondensible Gases From the Steam Jet-Air Ejector

The first release of radioactive gases occurred through the steam jet-air ejector. Under normal operating conditions, radioactive gases are produced by fissions, decay and neutron capture and can be found at low concentrations in the primary coolant. Because the primary coolant is under high pressure, some of the gases remain dissolved. At Ginna, the rupture of one of the steam generator tubes resulted in a transfer of some of the primary coolant to the secondary side of the steam generator, which is at a lower pressure than the primary system. After depressurization, the radioactive gases came out of solution and flowed with the steam to the main condenser. The steam jet-air ejector draws noncondensible gases from the condenser and ejects them to the environment.

The steam jet-air ejector effluent resulted in the release of noble gases to the environment. (Most of the noncondensible gases with half lives longer than a few seconds are noble gases.) Some tritium may also have been released in water vapor. The Task Force estimates that the release of tritium was negligible compared with the release of noble gases at this time. Essentially no iodines or other nongaseous fission or activation products were likely to have been released by this pathway to the environment, because the condenser effectively removes them from the gas phase.

Noncondensible gases flow out of the steam jet-air ejector at the rate of about 5 cfm. These gases are combined with about 600 cfm of air from the gland seal condenser. This combined flow is called "off-gas." The combined volumes exhaust through an 8-in.-diam pipe to the roof of the turbine building. The off-gas pipe has two permanent radiation monitoring devices. One, referred to as R-15, is affixed to the outside of the 8-in. outlet pipe. The other off-gas monitor, SPING, draws samples continuously from the same 8-in. line as the R-15 monitor. Its samples are drawn approximately a foot above R-15. The licensee used the readings from the R-15 and SPING radiation monitors to determine the releases from this pathway. However, because one monitor was off-scale for a short time, and because the monitors could also have been influenced by external radiation, the Task Force performed an independent calculation of the releases from the steam jet-air ejector.

The radioactivity released from the steam jet-air ejector to the environment was estimated by assuming that all noble gases in the primary coolant that leaked from the reactor to B steam generator before main steam isolation valve closure were released from the steam jet-air ejector. In reality, some of these noble gases were probably released from the condenser after the isolation valve closed. However, no credit was given for hold-up; all releases were assumed to occur before closure. Noble gases in the primary coolant that leaked into the secondary side after the main steam isolation valves closed were assumed to have been released to the environment during the openings of the B steam generator safety valve. (See Section 5.4.2.)

The results of the Task Force calculations of leak rate from the reactor coolant system to the B steam generator are presented in Section 3.4. The leak rates for the period prior to the isolation of the B steam generator were multiplied by the reactor coolant system noble gas concentration that was measured before the rupture to get an upper-bound estimate of the noble gas activity released to the condenser, and then through the steam jet-air ejector to the environment. These releases are presented in the 9:00 a.m. to 10:00 a.m. column of Table 5.4.

5.4.2 Releases From the Safety Valves on B Steam Generator

The other major path for the release of radioactivity was from the Code safety valve on B steam generator, with the lowest setpoint, which opened five times to relieve the buildup of pressure in the steam generator due to the continued break flow following the closure of the main steam isolation valve. At the time of the releases through this valve, a considerable amount of primary coolant had already mixed with the secondary coolant. The dilution ratio of primary coolant in the secondary side was estimated both by comparing iodine concentrations in the primary versus those in the secondary, and by using the plant water inventory balance described in Section 3.6.

The Task Force used recordings of pressures and temperatures in the reactor and steam generator and the reports of operators to determine valve opening times. The safety valve openings are divided into two groups for this analysis. The openings between 10:38 a.m. and about 12:27 p.m. on January 25, accounted for the largest releases (see Section 5.4.2.1.) The safety valve released less radioactivity in openings which occurred between 10:19 a.m. and 10:28 a.m., on January 25. (See Section 5.4.2.2.)

Table 5.4 Calculated radioactivity released to the environment from the Ginna steam generator tube rupture, January 25, 1982

	Curies Released, Hour by Hour[a,b]							
	9 to 10 a.m.	10 to 11 a.m.[d]		11 a.m to Noon		Noon to 1 p.m.		
Radio-Nuclide	All Air-borne	Airborne Only	Near-Plant Fallout	Airborne Only	Near-Plant Fallout	Airborne Only	Near-Plant Fallout	Total Curies
H-3	0	4.91	4.38	4.9	7.99	0.99	1.62	24.8
I-131	0	0.0113	0.0179	0.0198	0.032	0.004	0.0065	0.092
I-132	0	0.375	0.595	0.506	0.825	0.089	0.144	2.53
I-133	0	0.14	0.223	0.24	0.391	0.048	0.078	1.12
I-134	0	0.0522	0.0822	0.045	0.074	0.0063	0.0102	0.27
I-135	0	0.174	0.276	0.279	0.455	0.054	0.088	1.33
Kr-85m	0.466[c]	1.07	0	0.308	0	0.146	0	1.99
Kr-87	0.865[c]	1.39	0	0.251	0	0.101	0	2.61
Kr-88	1.09[c]	2.31	0	0.591	0	0.269	0	4.26
Xe-133	11.0[c]	29.5	0	10.2	0	5.2	0	55.9
Xe-135m	0.929[c]	0.187	0	0.003	0	0	0	1.12
Xe-135	3.52[c]	8.8	0	2.8	0	1.38	0	16.5
Xe-138	2.85[c]	0.71	0	0.012	0	0.002	0	3.57
Ar-41	1.31[c]	2.45	0	0.535	0	0.23	0	4.53
Co-58	0	1.1×10^{-4}	0.029	2×10^{-4}	0.052	4×10^{-5}	0.011	0.092
Co-60	0	3×10^{-5}	0.0085	6×10^{-5}	0.016	1×10^{-5}	0.003	0.028
Mo-99	0	4×10^{-5}	0.011	7×10^{-5}	0.019	1×10^{-5}	0.004	0.034
Cs-137	0	2×10^{-5}	0.0064	4×10^{-5}	0.012	1×10^{-5}	0.0024	0.021
Ba-140	0	1.3×10^{-3}	0.351	2×10^{-3}	0.634	5×10^{-4}	0.128	1.12

[a] Number of significant figures presented does not reflect accuracy.

[b] Decay until the time of release has been accounted for.

[c] These releases were all or nearly all from the steam jet-air ejector or gland seal exhaust. All other releases were from the safety valve of B steam generator.

[d] The estimated curies released during this one hour period remain conservative, whether or not the Code safety valve leaked steam after its first opening at 10:19 a.m. The break flow noble gas activity was assumed to be released once it got into the steam generator, regardless of how released. The mass of steam that would have been released was assumed to be released as liquid at 10:38 a.m., which would over-estimate non-volatile radionuclide releases.

5.4.2.1 Major Releases From the Safety Valve

The lowest setpoint code safety valve for B steam generator opened three times between 10:38 a.m. and 12:27 p.m. The behavior of the safety valve suggests it was passing liquid or two-phase flow during these openings. Calculations of the reactor coolant system water which would have accumulated in B steam generator as a result of the estimated break flows indicated that the main steam line was filled with water up to the main steam isolation valve.

Two-phase flow models currently in use in the nuclear industry (e.g., Moody, 1979) predict that the mass flow rate for high-pressure flow through a small cross-sectional area (such as a safety valve) is larger when the upstream fluid is saturated or subcooled water rather than saturated steam. One of these models (Moody, 1979, pp. 3, 18 and 19) was used to estimate the upper bound of the mass flow rate out of the safety valve.

The Task Force further concluded that the Code safety valve failed to fully close after the last opening (See Section 3.6), and estimated that about 600 lb/min were released from about 11:37 a.m. to 12:25 p.m., January 25. The total amount of steam and water released from the last openings and the valve leakage is estimated to be about 111,000 lb.

The radionuclide releases are shown in Table 5.4. All the radionuclides in the released mass of secondary coolant, as liquid, are estimated to have been released to the environment. This estimate is supported by the concentrations of cobalt, molybdenum, and cesium in snow samples near the plant. (These elements are generally in nonvolatile chemical form; their existence would not be expected from a "dry" steam release.) The concentrations of the noble gases were determined from the concentrations in the reactor coolant system before the event, the amount of coolant leaked into B steam generator between openings of the safety valve, and the dilution in the steam generator water. The concentrations of the other radionuclides were determined by the estimated transfer and dilution of primary and secondary water, and the secondary water concentrations after the event. The most reliable concentrations appear to have been from the B steam generator samples taken at 12:30 p.m., and shown in

Table 5.3. The variation of the steam generator concentrations between the time of the tube rupture and 12:30 p.m. was modeled as a function of time to estimate the amount of radionuclides released.

The estimates of noble gas releases for the period 10:00 a.m. until 1:00 p.m. on January 25 may be conservative. The estimate includes the assumption that essentially all the noble gases in the coolant that leaked into the B steam generator were released to the environment. The configuration of the main steam line is such that the safety valves are at an elevation well below the top of the steam generator and would be sealed with water when the line flooded during the event. Noble gases that came out of solution on depressurization through the break would likely collect at a high point in the steamline, and thereby become unavailable for release, except at the much lower concentrations determined by their solubility. Evidence that the noble gas release figures may be conservative was provided by the discovery of a large gas volume in the B steam generator containing tens of curies of noble gases (See Section 7.2.1).

During this event, the estimated releases of iodine did not exceed those calculated for the design-basis steam generator tube rupture, since the design-basis analysis assumes an iodine-spiking factor (apparently not present during the event) and a reactor coolant iodine activity concentration equal to Technical Specification limits. (Actual reactor coolant iodine activity concentration prior to the event was approximately 2% of the Technical Specification limit.) However, the Task Force estimates of the proportions of available iodine and particulate radionuclides released, relative to the initial concentration of these radionuclides in the reactor coolant system, exceed that ratio assumed in the design basis steam generator tube rupture analysis. During the event, a faulted steam generator Code safety valve relieved water in the liquid phase as a result of the break flow flooding the main steam line. The release of liquid, rather than steam, as is assumed in the design-basis analysis, results in a release of a large proportion of the available iodine in the faulted steam generator because during a liquid release there is no partitioning of iodine between the liquid and vapor phases. The design-basis analysis assumption that only steam releases occur favors the retention of iodine in the steam generator water due to partitioning.

Finally, the releases of nonvolatile cobalt, cesium, barium and molybdenum nuclides during this event exceed those assumed in the design-basis analysis, since the design-basis analysis assumes steam releases which would not contain these radionuclides.

The Auxiliary Building ventilation particulate and iodine radiation monitors alarmed at about 11:43 a.m. on January 25; the noble gas radiation monitor alarm from the same ventilation duct did not sound.

5.4.2.2 Small Releases From the Safety Valve

Relatively smaller amounts of steam were released during the first two openings of the safety valve for B steam generator. Unlike the later releases, these releases from 10:19 to 10:28 a.m. probably occurred before the steam generator was full. Little iodine was assumed to have been released, because of its low volatility. The mass concentration of iodine in the steam was assumed to be lower by a factor of 40 than the concentration in the liquid. Up to 1% of the material released was assumed to be water in the form of fine droplets. This 1% carryover of droplets also accounts for the amount of cobalt, molybdenum, cesium, and barium released. None of the latter was assumed to have been released as vapor. In Table 5.4, releases of cobalt, molybdenum, cesium, and barium are presented in two columns for this period, to reflect the estimate that almost all these radionuclides fell near the plant instead of offsite. The concentration of tritium in the steam released was assumed to be the same as that in the steam generator liquid.

The noble gases released during these openings were estimated by assuming that all the noble gases in the primary coolant that leaked between 9:40 a.m. and 10:28 a.m. were released to the environment. Concentrations for radionuclides released were determined, as discussed in the previous section.

5.4.3 Releases From the Steam-Turbine-Driven Auxiliary Feedwater Pump

Following the steam generator tube rupture, a potential pathway for release to the environment was the steam exhaust from the turbine-driven auxiliary feedwater pump that supplies water to the secondary side of the steam generators. After a safety injection activation, auxiliary feedwater pumps are used in preference to the main feedwater pumps. At Ginna, one of the auxiliary feedwater pumps is driven by a steam turbine and the steam supply can come from either one or both steam generators. The exhaust from this steam turbine is directed to the atmosphere. The steam supply to the turbine driven auxiliary feedwater pump was provided shortly after the start of the event. However, the steam supply to this turbine from B steam generator was closed within 3 min. after the pump was started, and therefore contaminated steam was exhausted to the atmosphere for only 3 min. A small fraction of the noble gases released to the environment during the early part of the event went through this pathway and is included in the 9:00 a.m. to 10:00 a.m. column in Table 5.4.

5.4.4 Releases From the A Steam Generator Atmospheric PORV

Releases from the A steam generator atmospheric PORV (sometimes known as the atmospheric dump valve) began at 10:40 a.m. January 25, after the event. By 6:30 p.m., the same day, there were at most 50 µCi dose equivalent (DE) I-131 in the A steam generator. From 10:40 a.m. until cold shutdown was achieved, the Task Force estimates that no greater than 100 µCi DE I-131 was released to the environment from this pathway, far less than that released from the B steam generator.

5.4.5 Offsite Transport of Airborne Radioactivity Releases

The Task Force estimated that much of the radioactivity released, other than noble gases, condensed and fell near the plant. The releases from about 10:38 a.m. to 12:27 p.m., probably occurred in a flashing steam-water mixture. For tritium and iodines, the calculated flashing fraction* was assumed to remain airborne and available for offsite release. The remaining tritium and iodine were assumed to have condensed and fallen out on the roofs of the turbine and auxiliary building and onto nearby areas. For cobalt, molybdenum, cesium, and barium, which are less volatile, only 1% of the flashed fraction was assumed to remain airborne as very fine particles. The remainder of these nuclides were assumed to have fallen nearby. These airborne and condensate releases are listed in the 11:00 a.m. to noon and the noon to 1:00 p.m. columns of Table 5.4 and constitute part of the releases listed from 10 to 11 a.m.

The earlier releases from the safety valve probably occurred as dry steam, and for these releases, all the iodine and noble gases were assumed to remain airborne. Only 1% of the cobalt, molybdenum, cesium, and barium was assumed to have stayed airborne long enough to get offsite. The remainder was assumed to fall nearby. These releases are included in those listed in the 10:00 a.m. to 11:00 a.m. column of Table 5.4.

Table 5.4 provides a summary of the Task Force estimate of the releases to the environment resulting from the event. The Task Force estimated that a total of about 90 curies of noble gases were released, mostly from the steam jet-air ejector. About 0.4 curies of dose-equivalent I-131 (a total of about 5 curies of all isotopes of iodine), and about 1.3 curies of cobalt, molybdenum, barium, and cesium were released, mostly from the openings of the safety valve. About 25 curies of tritium may have been released, with trace amounts from the air ejector, but mostly from the safety valve openings.

5.5 Pathways for Liquid Releases to the Environment

This section discusses the pathways for liquid releases of radionuclides to Lake Ontario during the event. These pathways include nonvolatile radionuclides in liquid effluent from monitored discharges of the plant retention tank and the steam generator blowdown tank. The data were taken from the licensee's Liquid Waste Release Forms. Liquid releases from the site due to melting snow and yard and roof drainage are not discussed, since the related radioactivity released is included in atmospheric release estimates and should not be counted twice. Liquid discharges flowed into Lake Ontario through a discharge canal, which was sampled for radioactivity during and after the event. No concentrations of any radionuclide above background were detected.

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*Flashing fraction refers to that fraction of water that becomes steam when undergoing a rapid depressurization.

5.5.1 Plant Retention Tank Release

The retention tank receives water from floor drains in the Turbine Building and normally uncontaminated parts of the Intermediate Building. Potential pathways for radioactivity to the retention tank resulting from the tube rupture event are from minor leaks in the secondary water system and from a drain line from the Code safety valve line. The radioactivity from both these sources is expected to have increased as a result of the tube rupture. The retention tank was sampled at 10:30 a.m., January 25, and had a total gross activity concentration of 5.5×10^{-6} μCi/g. Based on this concentration and the total of 67,000 gal released from the tank to the circulating water canal, the Task Force verified the licensee's calculation of 1.4 millicuries of total activity released. The retention tank discharge lasted roughly 23 hours. No activity above background was observed in the samples of the discharge canal, indicating that the total activity released was small.

5.5.2 Steam Generator Blowdown Tank Release

The steam generator blowdown tank is part of the secondary chemistry control system. Secondary water is released from each steam generator to the blowdown tank so that nonvolatile chemicals or crud will not build up in the steam generators. During the first part of the Ginna event, B steam generator water, contaminated because of the rupture, was released to the blowdown tank. The blowdown line from the B steam generator was valved off during containment isolation, but it may have leaked thereafter. The blowdown tank was sampled and released at 9:00 p.m. the same day, and the total gross activity concentration was 3.4×10^{-4} μCi/g. An estimated maximum of 1400 gal was released, resulting in a total radioactivity release of about 1.5 to 1.8 millicuries.

5.6 Releases Compared With Ginna Technical Specifications Release Limits

The releases of radioactivity during the event were compared with the Ginna Technical Specifications for controlled releases of radioactive liquids and gases, Section 3.9, "Plant Effluents." The objective of this specification is to "define the conditions for release of radioactive wastes to the circulating-water discharge and to the plant vent," to assure releases are as low as practicable. This specification is not truly applicable to the Ginna event, because the releases during the Ginna event were not controlled. However, this is a useful comparison to give a perspective on the magnitude of the releases.

The limits for liquid waste in Technical Specification 3.9.1 are 1×10^{-7} μCi/g for gross beta activity excluding tritium, and 3×10^{-3} μCi/g for tritium, above background, in the circulating water discharge. Samples of the circulating water discharge taken on January 25 and 26 showed no radioactivity above background. Also, the Task Force calculated, based on sample concentrations, release volumes, and circulating-water flow rate dilution that neither release resulted in circulating-water discharge concentrations above the limits.

The limits for controlled releases of gaseous wastes are defined in Technical Specification 3.9.2. There are two different limits for two different groups of radioisotopes, based upon their relative long-term effects in ecological chains. The limits on gross activity, except for airborne iodines and particulates with half-lives greater than eight days, is defined by the following equation:

$$\sum_i \frac{Q_i}{(MPC)_i} \leq 2.0 \times 10^5 \text{ m}^3/\text{sec}$$

where Q_1 is the release rate (Ci/sec) of any radioisotope i, and $(MPC)_i$ is the maximum permissible concentration, in Ci/m^3 (μCi/cm^3), in air as defined in

Column 1, Table II of Appendix B of 10 CFR Part 20. The Task Force estimated that this limit for controlled releases of gaseous wastes may have been exceeded, by as much as 27%, when the airborne releases for these nuclides, as shown in Table 5.4, are averaged over the 3-hr period from 9:25 a.m. to 12:27 p.m., January 25.

The limits on controlled release of iodines and particulates with half-lives longer than 8 days, are defined by the following equation:

$$\sum_i \frac{Q_i}{(MPC)_i} \leq 290 \ (m^3/sec)$$

The Task Force estimated that this limit for controlled releases may have been exceeded by as much as a factor of 14, based on the airborne releases for these nuclides as shown in Table 5.4, when averaged over 24 hr, as permitted by the Technical Specification.

5.7 Radiological Environmental Monitoring

This section presents an analysis of the radiological environmental sampling data collected by NRC and the licensee during the Ginna event. Data were taken from air samples, water samples, thermoluminescent dosimeter (TLD) measurements, survey instrument measurements, and snow samples. Population and worker doses are discussed in Sections 5.8 and 5.9.

5.7.1 Thermoluminescent Dosimeter Data

Thermoluminescent dosimeters are exposure-integrating devices, which measure total or cumulative exposure rather than the rate of exposure. Thermoluminescent dosimeters placed by NRC, New York State, and by the licensee as part of their respective routine monitoring programs, were in place throughout the course of the event. The licensee and New York State had thermoluminescent dosimeters located onsite and offsite. NRC had thermoluminescent dosimeters situated offsite only. The licensee also placed additional thermoluminescent dosimeters offsite following the event. New York State's thermoluminescent dosimeters were removed January 25 and processed to determine the exposure incurred. The licensee's and NRC's thermoluminescent dosimeters were removed on January 29, and processed. Thermoluminescent dosimeters are normally changed at quarterly intervals.

Offsite thermoluminescent dosimeter readings by NRC, the licensee and New York State indicated exposure levels during the event were about the same as expected from background radiation sources. With the exception of two thermoluminescent dosimeters onsite that were situated approximately 0.2 mile downwind (SE) of the release point, no thermoluminescent dosimeter measurement indicated an exposure significantly above background. The two thermoluminescent dosimeters that recorded a significant exposure (21.7 ± 2.7 millirems and 9.4 + 0.9 millirems) were located at the approximate centerline of the predicted plume. Most of these thermoluminescent dosimeter exposures probably came from radioactive materials deposited on the ground and nearby surfaces rather than from the plume itself.

5.7.2 Air Monitoring

The licensee's fixed air-sampling stations were operating throughout the event. The licensee also dispatched survey teams shortly after the event to sample airborne contamination. Three sampling locations exhibited iodine concentration levels above background. These levels and their locations are specified in Table 5.5. These samples were downwind from the plant.

On the day of the event instantaneous iodine concentrations higher than the annual average permitted by 10 CFR Part 20 were measured only at location c. However, within 4 days of the event the iodine concentrations had decreased to less than the 10 CFR Part 20 limits, and by February 5, 1982 the concentration levels were less than the detectable limits of the instrumentation. Consequently, this short-term presence of iodine concentration in excess of 10 CFR Part 20 values would have little effect on the annual average concentrations normally observed at Ginna which are less than 5×10^{-14} μCi/ml for

Table 5.5 Rochester Gas and Electric air sampling data

Location Number	Sample Period Ending (time/date)	Average Concentration (μCi/ml)			
		I-131	I-132	I-133	I-135
a	1115 (1/25/82)	-	-	9.5×10^{-11}	-
	1413 (1/25/82)	-	-	8.2×10^{-11}	-
b	1243 (1/25/82)	-	-	9.3×10^{-11}	-
	1125 (1/25/82)	-	7.5×10^{-11}	7.4×10^{-11}	1.1×10^{-10}
c	1510 (1/25/82)	3.4×10^{-10}	-	3.8×10^{-9}	5.3×10^{-9}
	0800 (1/29/82)	1.4×10^{-12}	-	3.3×10^{-12}	-
	0748 (2/5/82)	$<3.0 \times 10^{-14}$	-	$<1.3 \times 10^{-13}$	-

[a] Intersection of Knickerbocker and Lake Roads (unrestricted area), approximately 1 mile ESE of plant.

[b] Intersection of Putnam and Fisher Roads (unrestricted area), approximately 3 miles ESE of plant.

[c] Onsite adjacent to Ginna Brookwood Training Center (Unrestricted Area), approximately 0.2 mile SE.

Table 5.6 Maximum permissible concentrations of radionuclides in air above natural background[a]

Isotope	Within Restricted Area Air (μCi/ml)		Unrestricted Area Air (μCi/ml)
Iodine-131	S[b]	9×10^{-9}	1×10^{-10}
	I	3×10^{-7}	1×10^{-8}
Iodine-132	S	2×10^{-7}	3×10^{-9}
	I	9×10^{-7}	3×10^{-8}
Iodine-133	S	3×10^{-8}	4×10^{-10}
Iodine-135	S	1×10^{-7}	1×10^{-9}
	I	4×10^{-7}	1×10^{-8}

[a] Excerpted from Appendix B of 10 CFR Part 20

[b] S = soluble

[c] I = insoluble

Iodine 131. The doses resulting from these measured radioiodine concentrations are small fractions of the design guideline values in 10 CFR Part 100.

At offsite locations a and b on January 25, the measured radioiodine concentrations were less than 25% of the maximum permissible air concentrations for unrestricted areas as specified in 10 CFR Part 20 and indicated in Table 5.6.

5.7.3 Water Samples

Onsite tap water samples and offsite samples at the Ontario Water Works were taken by the licensee. None of the analyses indicated radionuclide concentrations above minimum detection capability of the instruments and procedures used.

5.7.4 Snow Samples

During the event, snow was falling at a rate of about 1/4 inch per hour in the vicinity of Ginna. The licensee collected more than 100 snow samples from the ground, from vehicles and from buildings.

Because of the wide variability in area, depth, and density of the snow samples collected, measured concentrations of radioactive materials in snow could not be used to determine deposition quantitatively. However, a comparison of the relative concentrations for snow collected onsite and offsite demonstrated that a major portion of the radioactive materials was deposited within the site boundary. The samples further demonstrate that a significant proportion of the iodine available for release from the B steam generator was deposited in the snow on site.

5.7.5 Other Samples

In addition to the samples discussed in the previous sections, licensee survey teams made general environmental radiation level surveys using Geiger-Mueller and scintillation detection equipment. The highest verified exposure rate measurement made in the course of these surveys (3 millrems per hr) was obtained at the site fence, approximately 130 meters southeast of the release point at about 12 noon.

As expected from the low levels of environmental radiation measured by other more sensitive methods, environmental surveys, with one exception, did not show radiation levels above background levels beyond the plant boundary. The exception was a single measurement taken about 11:00 a.m. on January 25 at the intersection of Lake and Ontario Center Roads, which indicated an exposure of 1.2 millirads. Additional surveys early in the afternoon indicated that this area had returned to background. In addition, portable instrument surveys made offsite by Wayne County personnel did not indicate any radiation levels above background.

5.8 Dose Assessment From External and Internal Exposures

This section provides upper bound estimates of doses to the maximally exposed individual, and to the general population within 50 miles of Ginna, attributable to exposure to radioactive materials released from Ginna as a result of the event. Doses to individuals are compared with annual doses from exposure to natural background radiation.

5.8.1 Doses to Maximally Exposed Individuals

This section contains estimates of the doses to hypothetical persons who will be assumed to have received the maximum exposure possible both onsite and offsite. The estimated doses to an individual are based upon the quantities of radionuclides released, the meteorological dispersion that occurred as radionuclides were transported away from the release point, and the pathways of exposure to an individual. Most of the radionuclides from Ginna were released during the first three hours of the event. The maximally exposed individual onsite was assumed to have been located at the Brookwood Training Center, which is located about 0.1 mile southeast of the reactor on the plant site. The maximally exposed individual offsite was assumed to have been located at the downwind site boundary (i.e., about 0.3 miles from the plant in the southeast (SE) sector). Two methods were used to estimate doses to these maximally exposed individuals: (1) measurements of radionuclides in the environment near the Brookwood Training Center and near the southeast site boundary, and (2) environmental transport models (see Section 5.2) and measured concentrations of radionuclides in the reactor coolant system (see Section 5.3), as well as the estimated quantities of radionuclides released from the plant (see Section 5.4). The dose calculations are based on the assumption that an individual was present outdoors at these locations for the entire period of the releases. Hence, these dose estimates are probably substantially higher than actual exposures.

5.8.1.1 Onsite

Three thermoluminescent dosimeter stations were located onsite within 0.3 miles of the reactor in the downwind quadrant. The thermoluminescent dosimeter station located about 0.2 miles southeast of the reactor recorded an exposure of about 15 millirads above background radiation. The dose* to the whole body of the maximally exposed individual onsite was estimated to be about 15 millirems,** based on that measurement. The exposures measured by thermoluminescent dosimeters at the other two thermoluminescent dosimeter stations onsite in the downwind quadrant, as well as the exposures measured by the other onsite thermoluminescent dosimeter stations, were not significantly different from the exposures expected from natural background radiation.

The highest dose to any organ (e.g., the thyroid of an adult) of the maximally exposed individual onsite was unlikely to have exceeded about 40 millirems. This estimate is based upon the highest measured concentrations of radioiodines in air in the downwind quadrant (i.e., at the air monitoring station 0.2 miles southeast of the reactor in air samples taken at 11:25 a.m. and 3:10 p.m. on the day of the event. Results from the whole-body counting program (see Section 5.9.2) indicated no detectable iodine intake.

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*The term "dose" is used for brevity rather than the more precise term "dose equivalent."

**A millirem is a unit of radiation dose incurred, which can be related to the associated radiation risk to an exposed individual. One rem is equal to 1000 millirems. When an exposed individual incurs a number of millirems, the resulting number is an expression of his or her radiation dose. When a group of individuals is exposed, the collective dose to that group can be calculated simply by adding the doses incurred by each exposed member of the group. The resulting collective dose is expressed as person-rems or person-millirems, and is a measure of the associated radiation risk to the group as a whole. For purposes of this section, 1 millirem (mrem) = 1 milliroentgen (mR).

5.8.1.2 Offsite

The dose to the whole body of the maximally exposed individual offsite was estimated to be less than 5 millirems. The exposures measured by thermoluminescent dosimeters at the four nearest stations downwind of Ginna, as well as exposures measured by the other thermoluminescent dosimeter stations offsite, were not significantly different from the exposures expected from background radiation (see Section 5.8.3). These measurements include both exposure to direct radiation from radioactive noble gases in the plume, and exposure to radioactive materials on the ground. Based upon the environmental transport models used, the dose to the whole body of the maximally exposed individual offsite was estimated to be about 0.5 mrem from exposure to direct radiation from predicted radioactive noble gases in the plume (see Table 5.4).

The highest dose to any organ (e.g., the thyroid of a child) of the maximally exposed individual offsite was estimated to be less than five millirems. This estimate was based upon exposure assumed to the highest measured concentrations of radioiodines in air in the downwind quadrant. Assuming that a child breathed the highest atmospheric concentration of iodine-133 for six hours, the child would receive a thyroid dose of about 0.25 millirem. The release lasted for about three hours. Assuming that the other radioiodines were present in proportion to the quantities released from the reactor, and accounting for differences in locations, the highest dose to any organ is conservatively estimated as less than five millirems to the maximally exposed individual offsite.

5.8.2 Offsite Population Dose Commitments

Estimates of the dose commitments to the population within a 50-mile radius of Ginna were based upon measured quantities of radionuclides in the coolant system, estimated quantities released from the reactor, actual meteorological conditions during the releases, and the environmental transport and dosimetry models described in NRC Regulatory Guide 1.109. Estimates of dose commitment to the population within 50 miles of Ginna take into account both external exposure from radionuclides in the plume, and internal exposure from inhalation of radionuclides.

For the population within a 50-mile radius of Ginna, the total body population dose commitment from all pathways was estimated to be less than 0.1 person-rem.

5.8.3 Comparison of Doses With Natural Background Radiation

Man is continually exposed to ionizing radiation from natural sources. There are three primary sources of this natural background radiation: (1) solar and galactic cosmic radiation, (2) long-lived radionuclides in the earth's crust, and (3) radionuclides formed in the upper atmosphere from the interactions of cosmic radiation with gases in the atmosphere. The magnitude and variation in the radiation dose from these natural radiation sources provides one baseline for comparing the doses and the potential health impact from the Ginna event.

Estimates of the dose from background radiation at several locations in the United States are shown in Table 5.7. The estimated dose of less than 5 millirems to the maximally exposed individual offsite is approximately 4% of the annual dose of about 117 millirems from natural background radiation in Rochester, NY. The annual dose from natural background radiation in the United States varies from about 70 millirems to about 310 millirems, depending on location. The dose to the maximally exposed individual offsite is well within the range of variation in annual dose from natural background radiation in the United States.

The estimated dose to the total body of the maximally exposed individuals onsite and offsite from radionuclides released during the event are small fractions of the average annual dose from exposure to natural background radiation in the United States.

[redacted]

Table 5.7 Estimates of natural background radiation levels in the United States

Location	Annual Dose, millirems			
	Cosmic Radiation[a]	Terrestrial Radiation[b]	Internal Radiation[b]	Total
Albany, NY	41	25	28	94
Atlanta, GA	45	57	28	130
Binghamton, NY	44	46	28	118
Buffalo, NY	43	46	28	117
Denver, CO	75	90	28	193
Harrisburg, PA	42	46	28	116
Las Vegas, NV	50	20	28	98
New York, NY	41	46	28	115
New York State (avg)	42	45	28	115
Pennsylvania State (avg)	43	36	28	107
Rochester, NY	43	46	28	117
Washington, DC	41	35	28	105
United States	40-160	0-120	28	70-310

[a] Oakley, 1972, Tables 15, A-1 and A-2.

[b] National Council on Radiation Protection and Measurements, 1975, p.104

5.9 Occupational Radiation Exposures

5.9.1 Dosimetry Measurements on Plant Workers

On January 25, some plant personnel incurred radiation doses in the course of performing routine duties. Some plant personnel also incurred radiation doses while responding to the event. Some individuals were involved in both kinds of activities on that day.

Each individual whose duties required work in areas within which personnel monitoring is required was supplied with a film badge, a thermoluminescent dosimeter, and a pocket chamber. The dose values discussed below are based on pocket chamber measurements.

On the day of the event, 133 individuals worked under previously existing Radiation Work Permits and 24 individuals worked under Special Work Permits written to authorize specific, nonrecurring tasks. Eleven of these individuals were involved in both kinds of activities. The two groups combined included 146 individuals who accumulated a total collective dose of 644 person-millirems, for an average dose of 4.4 millirems. The maximum recorded individual dose on the day of the event was 240 millirems as compared with the limits specified in 10 CFR 20 of 1250 millirems for a three-month period for radiation workers.

These dose measurement results, in terms of person-millirems per day, can be evaluated against occupational radiation exposure experience at operating nuclear power plants. From 1976 through 1980, annual collective doses for workers at pressurized water reactors (PWRs) have varied from about 400 to 580 person-rems per plant, with an overall average of 474 person-rems per plant over the five-year period (NUREG-0713, Vol. 2).

A plant operating at the average annual exposure-accrual rate of 474 person-rems per plant would accrue exposure at an average of 1.3 person-rems per plant-day, or 1,300 person-millirems per plant-day. The total occupational radiation dose accrued at Ginna, on January 25, including that derived from responses to the event, was 644 person-millirems.

5.9.2 Detection of Personnel Contamination and Whole-Body Count Measurements

Radiation protection personnel monitored the individuals onsite who had been evacuated for possible contamination. They identified 11 individuals with detectable contamination. When these individuals were checked again at 1:30 p.m., 9 of the 11 had no detectable contamination and one individual had residual contamination only on his tee-shirt. When it was removed, no detectable contamination remained. For the remaining individual, the contamination was limited to the top of his head. Showering reduced the contamination level significantly. When a subsequent check showed that only one barely detectable spot remained the licensee determined that further decontamination was unnecessary.

To determine whether any of these 11 individuals had inhaled or ingested airborne contaminants, whole-body counts were performed on each within two weeks of the event. Six of the 11 individuals examined showed no detectable amounts of radioactive material, beyond natural background (principally potassium-40). The other five showed measurable quantities of cesium-137, which ranged from 3 to 11 nanocuries (nCi). This range is 0.01% to 0.04% of the maximum permissible body burden for this radionuclide. One individual had measurable quantities of cobalt-58 and cobalt-60 (0.3% and 0.13% of the maximum permissable body burden, respectively). That individual was known to have worked in areas containing airborne concentrations of radioactive materials prior to the event.

5.10 Risks to the General Public and to Plant Workers

In estimating the potential for detrimental health effects resulting from both onsite and offsite radiation exposures, the Task Force used somatic (cancer) and genetic risk estimators based on widely accepted scientific information. Specifically, the Task Force estimates are based on information compiled by the National Academy of Science's Advisory Committee on the Biological Effects of Ionizing Radiation (BEIR I, 1972). The estimates of the risks to the general public are based on conservative assumptions (that is, the doses estimated are probably higher than actual doses).

The following risk estimators were used to estimate health effects: 135 potential deaths from cancer per million person-rems and 258 potential cases of all forms of genetic disorders per million person-rems. The cancer-mortality risk estimates are based on the "absolute risk" model described in BEIR I. Higher risk estimates can be developed by use of the "relative risk" model, along with the assumption that risk prevails for the duration of an exposed individual's life. Use of the "relative risk" model would produce risk values up to about four times greater than those used in this report. The Task Force regards the use of the "relative risk" model values as a reasonable upper limit of the range of uncertainty. The lower limit of the range would be zero, because health effects have not been detected at doses in this dose range. The number of potential nonfatal cancers is approximately twice the number of potential fatal cancers, according to the 1980 report of the National Academy of Sciences's Advisory Committee in the Biological Effects of Ionizing Radiation (BEIR III, 1980). Values for genetic risk estimators range from about 60 to 1500 potential cases of all forms of genetic disorders per million person-rems (BEIR I, 1972).

The effects of radiation on living systems have for decades been subject to intensive investigation and consideration by individual scientists, as well as by select committees formed to assess radiation dose effects objectively and independently. As is the case with chemical contaminants, there is debate about the exact extent of the effects of very low levels of radiation from nuclear power plant effluents. However, the upper bound limits of deleterious effects from radiation are well established and amenable to standard methods of risk analysis. Thus upper bounds of the risks to the individual and the total population can be readily calculated. These risk estimates for the event at Ginna are presented below.

5.10.1 Risks to Individuals in the General Public

The risk to the maximally exposed individual is estimated by multiplying the risk estimators by the dose to the total body. Thus calculated, the risk of potential premature death from cancer to the maximally exposed individual offsite is less than one chance in one million. The risk of potential premature death from cancer to the maximally exposed individual onsite would be about two chances in one million. The risk of potential premature death from cancer to the average individual within a 50-mile radius of the reactor from exposure to radioactive materials released from Ginna is much less than the risk to the maximally exposed individual offsite. The risk is very small when compared to the probability of cancer from causes unrelated to the event at Ginna.

For comparative purposes, the Task Force has estimated the risk of potential premature death from cancer to the general public from one year's exposure to other sources of radiation in the United States (Table 5.8). These risks have been estimated using the same conservative assumptions that were used in estimating risks to the general public from exposure to radiation from Ginna.

[redacted]

Table 5.8 Approximate ranking of risks from various sources of radiation exposure in the United States

Source of Exposure	Exposed Group	Part of Body Exposed	Avg. Annual Dose,[a] mrem	Approx. Risk,[b] Chance of Premature Death in a Million
Medical diagnosis by radiopharmaceuticals	Patients	Bone marrow	300	40
Medical diagnosis by X-rays	Adult Patients	Bone marrow	103	14
Natural background radiation	Total population	Whole body	~80	11
Radioactive releases from Ginna	Maximum individual at Emergency Survey Center	Whole body	~15	2.0
Many types of radioluminous clocks	Users	Whole body	~8	1.1
Building materials brick and masonry	Population	Whole body	7	0.9
Radioactive releases from Ginna	Maximum offsite individual	Whole body	<5	<0.7
Atmospheric weapons tests	Total population	Whole body	~4	0.5
Unvented heaters using natural gas	Users	Bronchial epithelium	22	0.5
Airline travel	Passengers	Whole body	3	0.4
Dental diagnosis	Adult patient	Bone marrow	3	0.4
Many types of luminous wristwatches	Users	Gonadal dose equivalent	3	0.4
Natural-gas cooking ranges	Users	Bronchial	~7	0.2
Television receivers	Viewers	Gonads	~0.8	0.1

[a] Average annual doses for all sources, except the releases from Ginna, were taken from either BEIR III, 1980, or NCRP, 1977. The doses to the maximally exposed individual to radioactive effluents from Ginna are total doses, not annual doses.

[b] Risk was calculated by multiplying the average annual dose (in Rem) by risk estimates of 135 and 22.2 potential cancer deaths per million person-rem for total body and lung exposures, respectively. The total-body risk estimator was used to approximate the risk from the dose to the bone marrow from medical exposure.

The risk to the maximally exposed individuals onsite and offsite from exposure to radioactive materials released at Ginna is much less than the risk from exposure to any of the major sources of radiation (e.g., medical exposure and natural background radiation) and within the same range as the risks from exposure to many of the other common sources of enhanced radiation exposure (e.g., from airline travel, natural gas heat, and television viewing).

5.10.2 Risks to the General Public

Multiplying the population dose from exposure to radioactive materials released from Ginna (that is, less than 0.1 person-rems) by the preceding risk estimators, the Task Force estimated that the probability of one death from cancer over the lifetime of the entire population exposed as a result of the event is less than one in 50,000 and that the probability of one genetic disorder in all future generations of the entire exposed population as a result of the event is about one in 40,000. The significance of these risk estimates is best understood by comparing them with the overall incidence of cancer death and genetic abnormalities in the U.S. population. Multiplying the estimated exposed population around Ginna (approximately 64,000 persons) by the current incidence of actual cancer fatalities (approximately 20%) and the current incidence of actual genetic diseases (approximately 6%), about 13,000 cancer deaths and about 3,800 genetic abnormalities are expected (BEIR I, 1972; American Cancer Society, 1978). The risks to the general public from exposure to radioactive materials released from Ginna are very small fractions (less than seven parts in a billion) of the estimated normal incidence of cancer fatalities and genetic abnormalities in the exposed population.

5.10.3 Risks to Workers

The risk of potential fatal cancers to the exposed workforce and of potential genetic disorders in all future generations of the workforce at Ginna was estimated by multiplying the plant-worker-population dose (about 0.6 person-rem) by the risk estimators, the Task Force estimated that the probability of one cancer death over the lifetime of the entire work force as a result of exposure during the event is about one in 12,000, that the probability of one genetic disorder in all future generations of the entire work force as a result of exposure during the event is about one in 6500. The significance of these risk estimates can be evaluated by comparing them to the normal incidence of cancer deaths and genetic abnormalites in the exposed population. That is, multiplying the current incidence of actual cancer fatalities (approximately 20%) and the current incidence of actual genetic diseases (approximately 6%), by the estimated number of exposed individuals (i.e., 146), about 31 cancer deaths and about nine genetic abnormalities are expected (BEIR I, 1972; American Cancer Society, 1978).

5.11 References

American Cancer Society, "Cancer Facts and Figures - 1979," 1978.

BEIR I. National Academy of Sciences/National Research Council, Advisory Committee on the Biological Effects of Ionizing Radiation, "The Effects on Populations of Exposure to Low Levels of Ionizing Radiation," November 1972.

BEIR III. National Academy of Sciences/National Research Council, Advisory Committee on The Biological Effects of Ionizing Radiation (BEIR III), "The Effects on Populations of Exposure to Low Levels of Ionizing Radiation," July 1980.

F. J. Moody, "Maximum Discharge Rate of Liquid-Vapor Mixtures From Vessels," NEDO-21052-A, General Electric, San Jose, California, 1979.

National Council on Radiation Protection and Measurements, NCRP, 1975, "Natural Background Radiation in the United States," NCRP Report No. 45, November 1975.

National Council on Radiation Protection and Measurements, NCRP, 1977, "Radiation Exosure from Consumer Products and Miscellaneous Sources," NCRP Report No. 56, November 1977.

NUREG-0713, Vol. 2, "Occupational Radiation Exposure at Commercial Nuclear Power Reactors - 1980," U.S. Nuclear Regulatory Commission, December 1981.

D. T. Oakley, "Natural Radiation Exposure in the United States," EPA Report ORP/SID 72-1, U.S. Environmental Protection Agency, Washington, D.C. (1972).

Regulatory Guide 1.109, Rev. 1, U.S. Nuclear Regulatory Commission, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I."

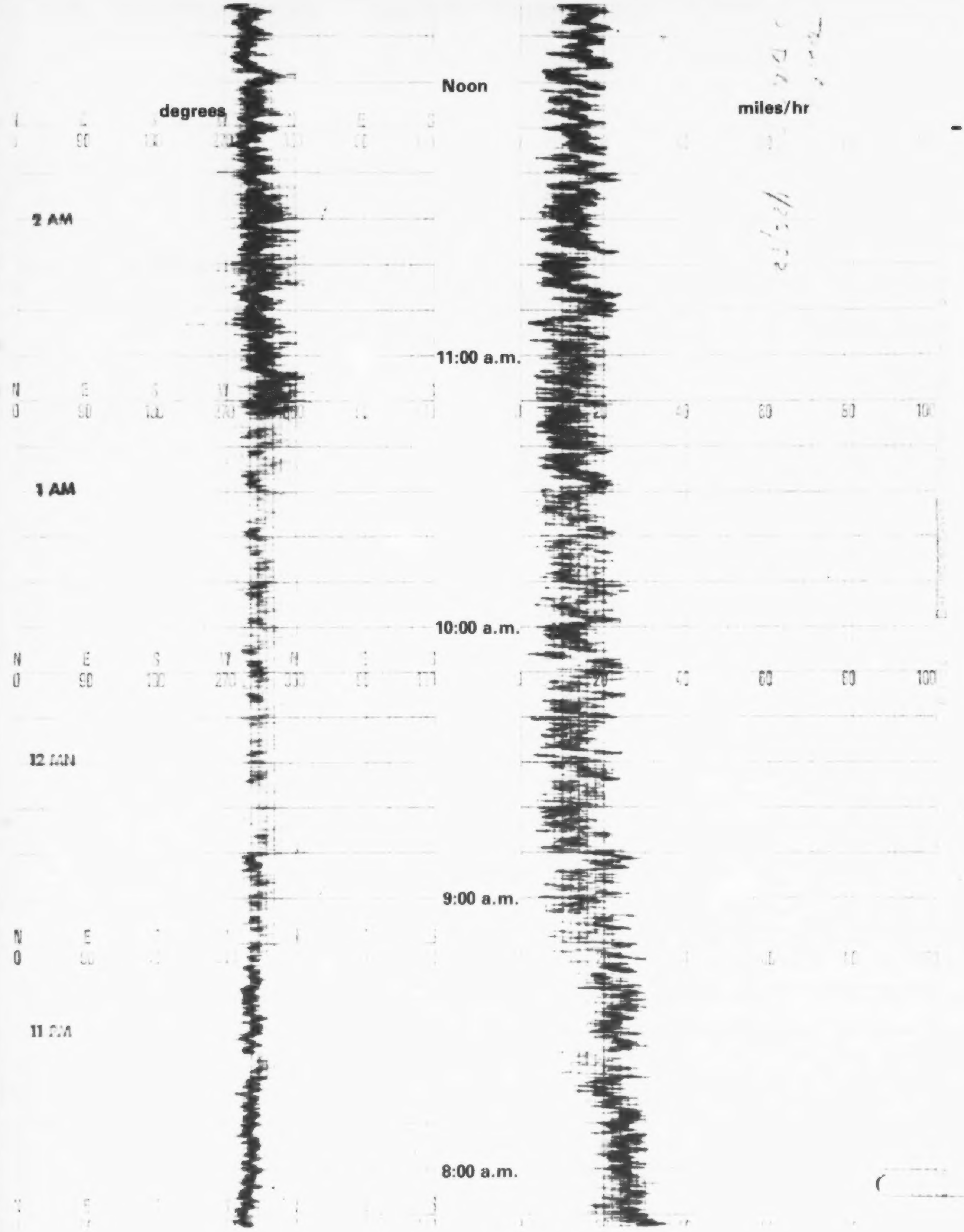

Figure 5.1 Wind speed and direction, 33-ft level, primary tower

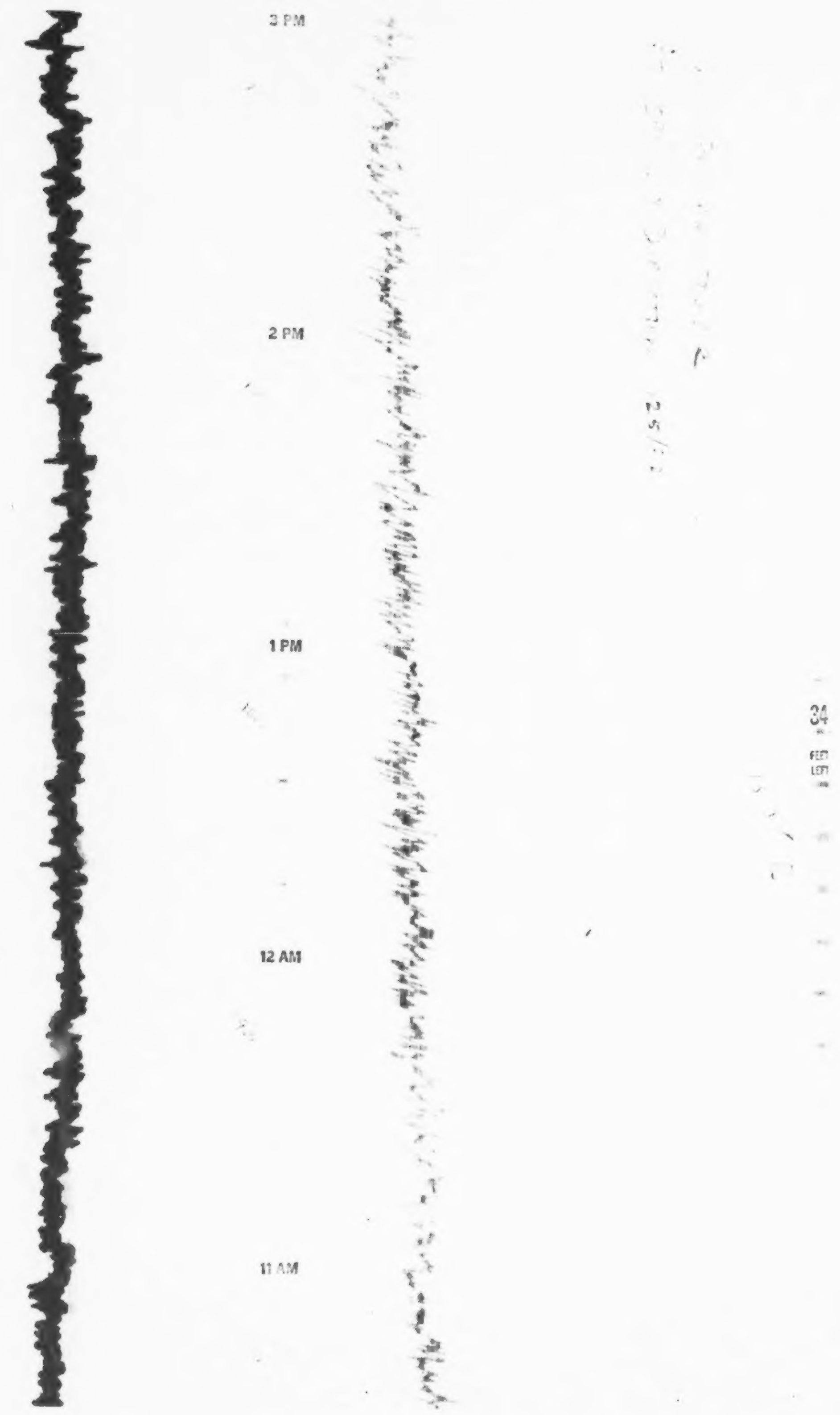

Figure 5.2 Wind speed and direction, 150-ft level, primary tower

BEST DOCUMENT AVAILABLE

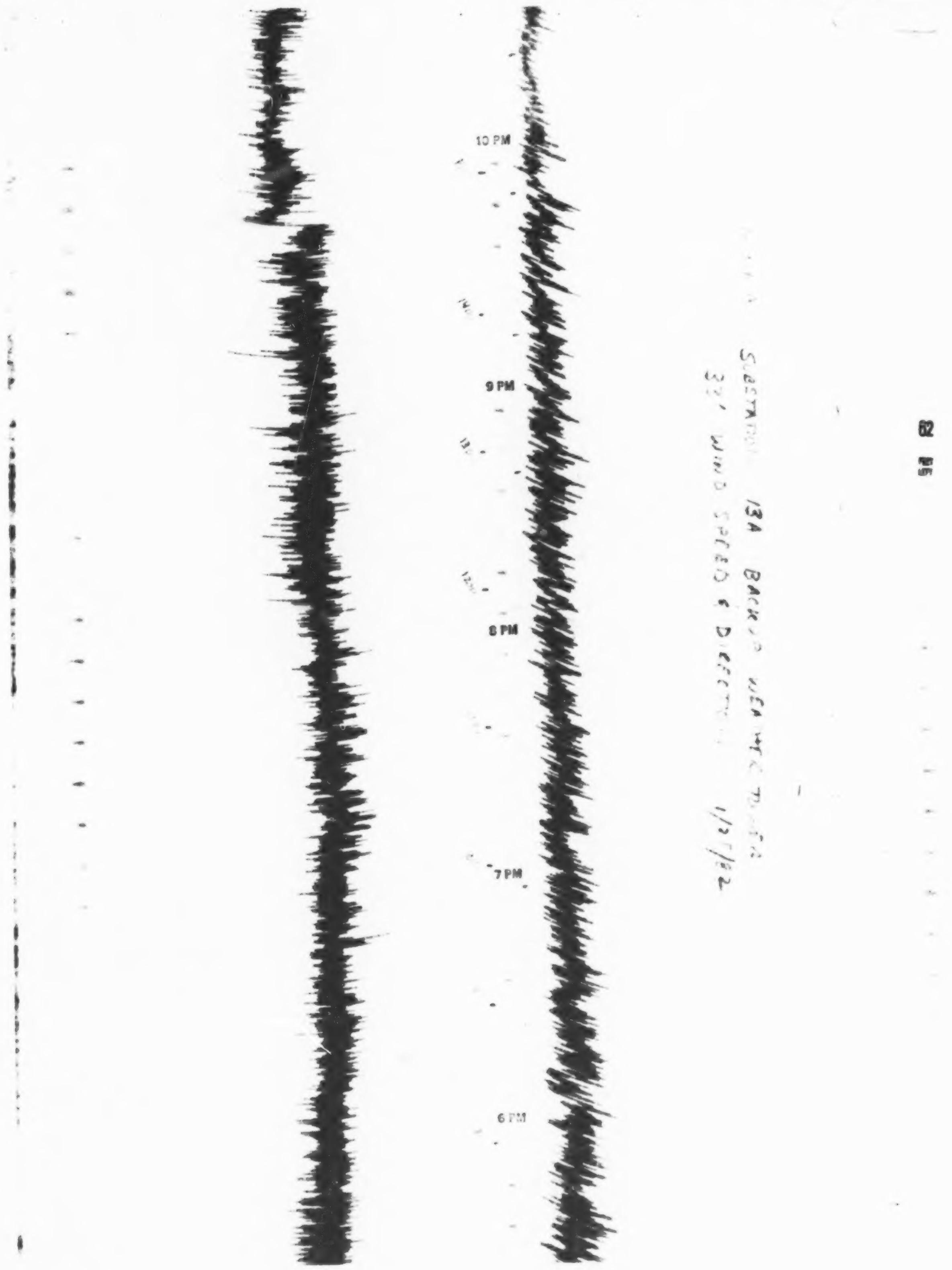

Figure 5.3 Wind speed and direction, 33-ft level, backup tower

BEST DOCUMENT AVAILABLE

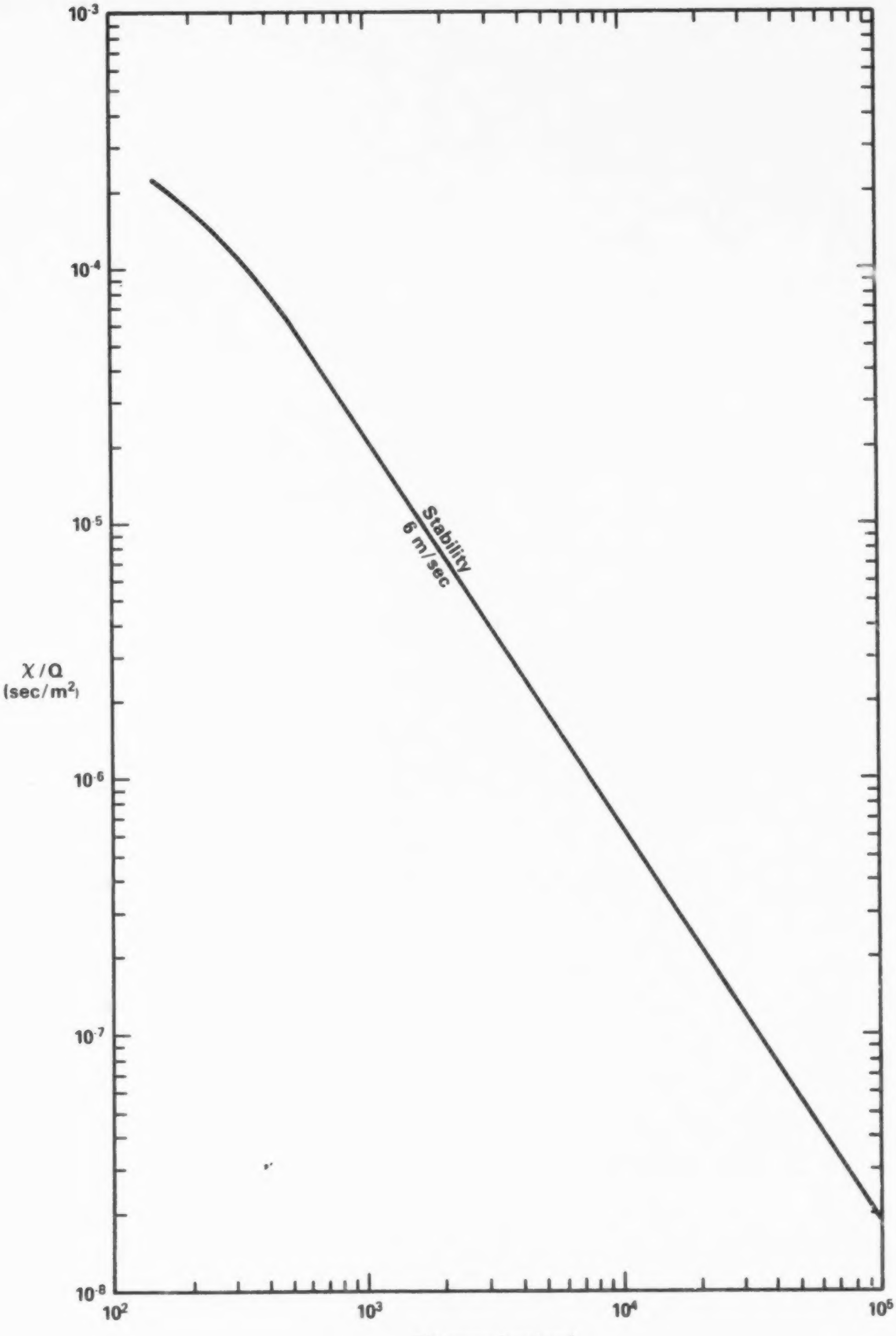

Figure 5.4 Dilution vs. distance for the Ginna site on January 25, 1982

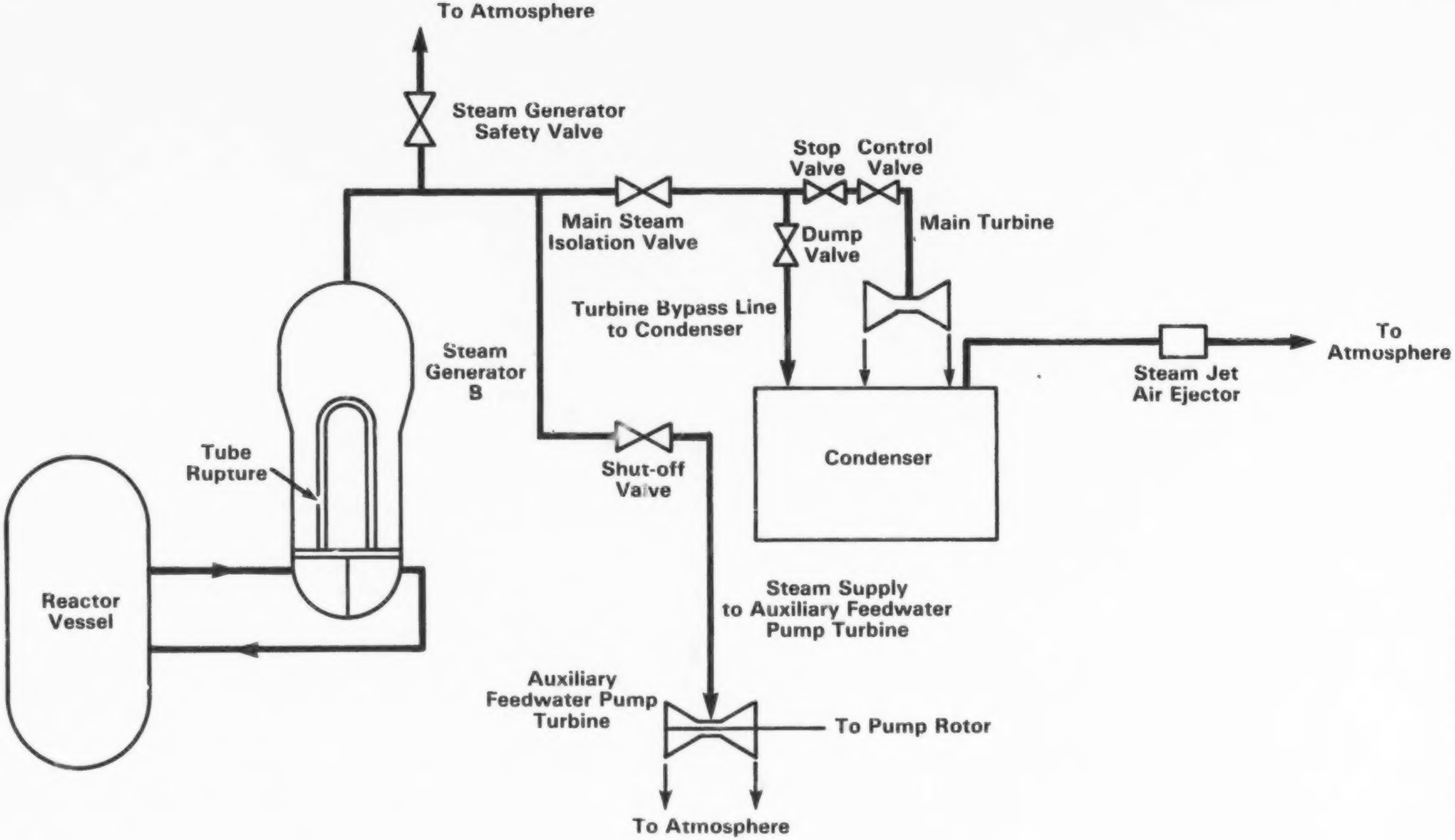
To Atmosphere
Steam Generator Safety Valve
Stop Valve
Control Valve
Main Steam Isolation Valve
Dump Valve
Main Turbine
Turbine Bypass Line to Condenser
To Atmosphere
Steam Generator B
Steam Jet Air Ejector
Tube Rupture
Shut-off Valve
Condenser
Reactor Vessel
Steam Supply to Auxiliary Feedwater Pump Turbine
Auxiliary Feedwater Pump Turbine
To Pump Rotor
To Atmosphere

Figure 5.5 Pathways for release of radionuclides to the environment from the Ginna steam generator tube rupture on January 25, 1982

6 ORGANIZATIONAL RESPONSES

This chapter assesses the organizational responses to events at the Ginna Nuclear Power Plant on January 25 and 26, 1982, and compares the actual responses with those prescribed in the procedures and plans of the licensee, State and local governments, NRC regional and headquarters staff, and other Federal agencies.

6.1 Licensee Response

6.1.1 Classification of Event

At 9:33 a.m., the Ginna Shift Supervisor on duty called the NRC Headquarters Operations Center using the Emergency Notification System phone in his office to report an Unusual Event at the plant because of the steam generator tube rupture that had occurred at 9:25 a.m. Shortly thereafter, a non-shift licensed operator at Ginna took the call over from the Shift Supervisor and maintained the line open from the control room.

At 9:40 a.m., the Plant Superintendent, after consulting with the Shift Supervisor and the Operations Engineer, declared a plant Alert in accordance with guidelines in the plant's Emergency Operating Procedures.

This declaration was appropriate in view of the steam generator tube rupture, reactor trip, and safety injection, and is in agreement with the requirements of Emergency Operating Procedure E-1.4 "Steam Generator Tube Rupture," and Criterion 3.9b for Alert Status Evaluation in procedure SC-1.1A. The plant Alert was announced over the public address system from the control room according to procedures SC-1.2B and the utility's Technical Support Center (TSC) was manned in accordance with procedure SC-1.3D.

At 10:44 a.m., the licensee's Plant Superintendent, now functioning in the role of Emergency Coordinator, declared a Site Area Emergency. The plant experienced a temporary loss-of-coolant accident (LOCA) because of a large primary-to-secondary leak, and a stuck-open pressurizer power-operated relief valve (PORV). A steam bubble had developed below the reactor vessel head, and the steam generator safety valves were opening, thus providing a direct path to the atmosphere for the reactor coolant. The position indicator recorder for the steam generator safety valve failed and personnel in the Technical Support Center and control room were unable to estimate the amount of radioactive material released at that time. The conditions described by the Emergency Coordinator as a basis for declaring a Site Area Emergency were in accordance with criteria 3.4, 3.14, and possibly 3.9 listed on the Site Emergency Evaluation sheet in procedures SC-1.1A. The Emergency Coordinator discussed plant conditions with the TSC staff and the declaration of a Site Area Emergency was determined to be the most prudent course of action at that time.

The declaration of a Site Area Emergency required that nonessential personnel be evacuated from the site and that radiological survey teams be formed. The survey teams, however, had already been organized after declaration of the Alert and four of the five teams were already proceeding with the survey. One team was delayed because of some contamination received at the onset of the incident. That contamination was detected following procedure SC-1.30 for manning the Technical Support Center. The two men involved in the contamination joined the survey teams after they were decontaminated.

At 7:17 p.m. on January 25, the Emergency Coordinator downgraded the plant status from a Site Area Emergency to an Alert. By that time the plant was being cooled by forced circulation and steam was being expelled from the intact A steam generator to the atmosphere. The faulted B steam generator was being fed by auxiliary feedwater and bled through the tube rupture to the reactor coolant system. Members of the Plant Operations Review Committee (PORC) recommended that circumstances no longer justified a Site Area Emergency, as described in procedure SC-1.1A, since the plant was in a slow controlled cooldown. Licensee officials at the Emergency Operations Facility had been consulted and concurred with the de-escalation. This decision was also concurred in by the NRC Director of Site Operations after consultation with the NRC Site Team.

At 10:45 a.m. on January 26, the Emergency Coordinator further downgraded the event to Recovery phase, after justifying the change in status to officials at the Emergency Operations Facility. Because the plant was not in cold shutdown at this time, utility officials at the Emergency Operations Facility were concerned that downgrading the plant status might be premature because of the possibility of additional difficulties. However, by that time the overpressurization protection system was in service and the residual heat removal system had been operating for more than four hours. After consulting with the NRC Site Team, the Technical Support Center staff, and other personnel at the Emergency Operations facility, the Emergency Coordinator assured utility personnel at the Emergency Operations Facility that the situation was completely under control and that cold shutdown would soon be accomplished. Further, procedure SC-1.1A, which deals with classifying events at Ginna, contained no criteria to justify continuing the Alert status. The decision to downgrade the Event to the Recovery phase was concurred in by the NRC Director of Site Operations.

A review of the Ginna Emergency Plan and Emergency Plan Implementing Procedures indicated that neither contained a De-escalation phase and neither addressed the technique for an orderly de-escalation of emergency response. As a result, the licensee decided to reverse the Event classification sequence and select the emergency classification which appeared to best represent plant conditions and planned activities. Because symptoms for entry into each classification and the activities required following declaration of each classification are designed to address an escalating emergency situation, the selection of the correct classification during this plant recovery was not always obvious. The releases terminated, an emergency situation no longer existed, even though the plant was in a degraded condition.

6.1.2 Technical Support Center (TSC)

At 9:58 a.m., 33 minutes after the steam generator tube rupture, the Technical Support Center was fully manned and operational. The Technical Support Center staff consisted of the Emergency Coordinator, the Emergency Coordinator's Assistant, the Plant Assessment Manager, the Dose Assessment Manager, the Administration/Communications Manager, Survey Center Manager (located in the

Emergency Survey Center), Security Manager, Plant Health Physics/Chemistry Manager, Plant Technical Assessment Manager, Plant Maintenance Assessment Manager, and Plant Operations Assessment Manager. TSC staff positions and organization are listed in procedure SC-1.1B. Plant personnel qualified to fill TSC staff positions are listed in procedure SC-1.12A, with the exception of the Security Supervisor, who acted as the Security Manager during the event. The Technical Support Center was manned in accordance with procedure SC-1.3D. The licensee used a large organizational board to keep track of the Technical Support Center personnel on duty, although a permanent log was not maintained. The layout of the Center is shown in Figure 4.12. Communications between the Technical Support Center and other emergency centers and organizations were established immediately following its activation.

Control room communications were maintained with the Technical Support Center. (A layout of the control room is shown in Figure 4.1.) The initial notification of organizations offsite was made from the control room at the onset of the event by the Operations Engineer and the Shift Supervisor. Information was forwarded to Technical Support Center personnel manning the telephones in the form of "speed letters" (a preformatted information sheet). The information relayed in these letters appears to present a fairly accurate and timely accounting when compared with transcripts of the chronology of events.

TSC personnel provided the opportunity for the NRC Site Team and the NRC Senior Resident Inspector to participate in Plant Operations Review Committee meetings. (These meetings are discussed in Section 4.2.3.3.2.)

When the Site Area Emergency was declared, the Emergency Plan Implementing Procedures called for the plant evacuation alarm to be initiated, which the Emergency Coordinator in the Technical Support Center ordered done. Nonessential plant personnel evacuated to the Brookwood Training Center, which was approximately 75 to 100 yards downwind from the plant. Within 15 minutes of declaration of a Site Area Emergency, all personnel had been accounted for. Part of the evacuation assembly area was within the plume released from the plant because of the wind direction. During the evacuation nine people were slightly contaminated, mainly on their clothing. The Emergency Coordinator stated that the Technical Support Center staff was aware of the wind direction at the time of the evacuation alarm. Additional information concerning the contaminated individuals is documented in Chapter 5 of this report, as are the results of the radiological surveys. Information about personnel contamination and the results of the survey team dose assessments were relayed to the NRC Resident Inspector, to NRC Headquarters, and to NRC's Region I.

The Ginna Emergency Plan designated the Brookwood Training Center as the only evacuation site for personnel at the facility; the plan specified no alternate site, nor did NRC require one. Although radiation surveys were initiated at 10:33 a.m., they had not been completed in the area traversed by the evacuees before the declaration of the Site Area Emergency at 10:44 a.m.

The Emergency Coordinator stated that he was not aware of any major deviations from the plant's Emergency Plan Implementing Procedures for the Technical Support Center during this event. However, the Emergency Coordinator did indicate that some actions taken may not have been listed in the current revision of these Procedures. Ginna personnel were reviewing the Procedures at the recommendation of NRC's Emergency Preparedness Appraisal Team and Exercise Inspection Team. When the event occurred, the Emergency Coordinator implemented some of the improvements suggested to the licensee as the result of an emergency preparedness exercise conducted by State and local governments at Ginna on January 21, 1982. The changes consisted of activating the survey teams during the Alert phase of the event instead of waiting until a Site Area Emergency was declared, and stationing the Operations Engineer in the control room instead of in the TSC.

6.1.3 Emergency Operations Facility (EOF)

6.1.3.1 Activation and Staffing of the Emergency Operations Facility

At 9:33 a.m., NRC and the licensee's corporate office were notified about the tube rupture. At 9:40 a.m., the plant Emergency Coordinator declared a plant Alert. The Emergency Operations Facility was activated at approximately the same time that the plant Alert was declared.

[redacted]

By 11:25 a.m. the Emergency Operations Facility was fully operational, although log entries began at 9:40 a.m., when activation was initiated. The initial command staff was as specified in the plant Emergency Plan.

All emergency plans and implementing procedures were followed except for completion of the checklists designed for setting up the Emergency Operations Facility. These checklists were unnecessary because the Emergency Operations Facility was for the most part still set up from the exercise on January 21. The completion of the checklists would have served only as a reference. (The layout of the facility is shown in Figure 6.1.)

6.1.3.2 Emergency Operations Staff Decisions and Notifications

When the EOF was fully manned at 11:25 a.m., the Corporate Recovery Manager handed out NRC's Office of Inspection and Enforcement (IE) Information Notice No. 79-27, which provided information on the sequence of events that had occurred following steam generator tube ruptures at two other PWR units. The purpose of the handout was to familiarize all Command Center participants with what might be expected to occur.

The first press release was developed and approved by the Emergency Operations Facility at 11:30 a.m., January 25. At 11:15 a.m. on January 26, 1982, the 15th news release indicated that the Recovery phase of the event was under way. For additional information on media announcements, see Section 6.1.3.3, "Licensee Public Information."

The licensee's speed letters, notes from telephone conversations, and other notes indicate that they were in consultation with the reactor vendor during the event. These notes also indicated that the vendor had activated its TSC and was in communication with the licensee's Technical Support Center and Emergency Operations Facility staffs.

The interactions between the Emergency Operations Facility and State and Federal agencies are described in Section 6.1.3.4, "Governmental Interactions." Section 5 of the licensee's Emergency Plan, "Emergency Measures," provided guidelines for implementing procedures for the five emergency categories. The plan required initial notification of the State of New York in Albany, the New York State Bureau of Radiological Health, the Wayne County Office of Disaster Preparedness, and the Monroe County Office of Emergency Preparedness. The plan also called for keeping State and local governments advised of changing conditions.

During the event, the licensee used the New York State Radiological Emergency Communications System to update the State and counties on meteorological data, including temperature, wind speed, and wind direction readings from the 33-ft, 100-ft, and 150-ft levels of the weather towers at 30-minute intervals. In addition, one person from Monroe County arrived at 11:20 a.m., and two health physicists from the State of New York arrived at the EOF at 11:20 a.m. and 1:47 p.m., respectively. Two representatives from Wayne County arrived at 12:30 p.m. and 1:25 p.m., respectively, and a technician from New York State arrived at 3:30 p.m.

EOF dose assessment activities began, in parallel with the Technical Support Center, after the Emergency Operations Facility was fully staffed and management of the offsite survey team was transferred from the Technical Support Center to the Emergency Operations Facility. However, the results of the dose assessment activities were reported to the Technical Support Center. The licensee did not recommend that protective actions be taken to State or county officials, nor were they necessary.

6.1.3.3 Licensee Public Information

The licensee's Public Information Center was activated when the Emergency Operations Facility was activated. (See Figure 6.2 for a diagram of the Public Information Center.) Of the 140 media personnel arriving at the Center, all but 40 were photographed and issued badges before they were permitted onsite. The 40 not processed had already been issued badges from having covered the January 21 exercise. Other media people were issued badges as they arrived. The licensee made two consultants available to the press to answer questions about radiation.

The licensee followed the emergency plans and implementing procedures in dealing with rumors, the press, and the public. The licensee had 64 public information personnel on duty who responded to the approximately 1700 telephone calls that were received. They held 15 news conferences and posted 24 status reports in the Public Information Center. The licensee also held a public meeting with Ontario, New York residents on February 2, 1982.

6.1.3.4 Governmental Interactions

Representatives from New York State and county governments in the Emergency Operations Facility worked actively with the licensee's staff on communications with other State and county centers. They had access to all available information in the Emergency Operations Facility.

6.2 State and Local Governmental Responses*

6.2.1 State Response

At 9:46 a.m., the State of New York Warning Point received the initial notification that an Alert had been declared at Ginna through the Radiological Emergency Communications System (RECS). In accordance with the Radiological Emergency Preparedness Plan, the State Emergency Operations center (EOC) in Albany and the district EOCs in Wayne and Monroe Counties were partially activated and by 10:00 a.m., were staffed with representatives of the following State agencies: Office of Disaster Preparedness, Department of Health, Department of Conservation, State Police, and the Department of Agriculture and Markets. At 10:45 a.m., district EOCs were notified by the licensee through RECS that a Site Area Emergency had been declared. The State and district EOCs were fully activated by 11:20 a.m. At 11:30 a.m., shortly before being contacted by the Chairman of NRC, the Governor of the State of New York was briefed on the state of the event by the Director of the New York Department of Health.

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*The section on State and Local Governmental Responses was written by the Federal Emergency Management Agency in collaboration with the U.S. Nuclear Regulatory Commission.

In accordance with emergency procedures, the State dispatched three dose-assessment personnel and one operations person to the licensee's EOF in Rochester. Some of these personnel, dispatched from the Rochester and Syracuse offices of the Department of Health, arrived at the EOF, and called the State EOC at 11:20 a.m. A representative of the Department of Health who was assigned the function of operational assessment arrived at the EOF at approximately 4:00 p.m., and was briefed by the licensee on events at the site, including the formation and subsequent collapse of the steam bubble in the reactor vessel head. This information was not subsequently transmitted to the State EOC, which learned of the bubble the following day through the press.

6.2.2 Local Response

Both Wayne and Monroe County Warning Points were notified of an Alert at Ginna over the RECS when the State received its first notification. Both Counties immediately began activating their EOCs after notification. By 10:15 a.m., both EOCs were fully activated. Since the potential for evacution of the public at some future time existed, and since road conditions were hazardous, road maintenance crews were dispatched to plow and salt the evacuation routes. In addition, road blocks were positioned to control access to the Ginna site, although their use was never required. Monroe County decided not to dispatch field monitoring teams since the wind was blowing away from the County; nevertheless, all monitoring teams were put on standby. Wayne County monitoring teams were in the field by 11:40 a.m., and reported results back to the County EOC until 10:07 p.m., on January 25, 1982.

6.2.3 Communications and Intergovernmental Interface

The Radiological Emergency Communications Systems (RECS) was the primary communications link between the licensee's TSC and EOF with the State, county and district EOCs. This system was used to transmit information on plant status and offsite survey results to the State and counties.

The information plant status transmitted was identical to that recorded on status forms and posted in the EOF. Meteorological data was also received by the EOCs on a regular basis, which included stability class, wind direction and speed, and ambient temperature at the two instrument locations on the meteorological tower.

The NRC Chairman conferred directly with the New York State Governor and suggested that the State independently confirm the offsite radiological monitoring results being reported by the licensee. Since all offsite radiological survey reading results being reported to the State EOC from the Wayne County EOC were essentially background, the State indicated that they would collect for analysis their thermoluminescent dosimeters (TLDs) from around the site. These TLDs were collected by State police on the afternoon of January 25, even though replacement TLDs were not available. Replacement TLDs were posted on January 28.

After the Site Area Emergency had been declared, the Wayne County President of the Board of Supervisors, Monroe County Manager, and Director of the State EOC discussed whether or not to alert the public via the prompt notification siren system. They decided that the problem at the plant was not serious enough to result in significant releases, and that there was no need to notify the public at that time. On this basis, they mutually agreed not to use the prompt notification sirens.

After State and county personnel arrived at the EOF, direct phone communications were established between them and their respective EOCs. As information became available to the EOF, it was transmitted to the pertinent EOC.

6.2.4 Public Affairs

Both counties and the State sent Public Information Officers (PIOs) to the licensee's Joint Media Center (JMC), which is located in the same building as the EOF. All press releases developed at county EOCs were approved by the Monroe County Manager and the Wayne County President of the Board of Supervisors before they were released to the Joint Media Center. Information for press briefings was obtained by PIOs from their counties. The State PIO received information from State officials. Information given to PIOs by the licensee or other PIOs was confirmed through contacts with the respective EOC.

Only PIOs from the licensee, State and Wayne County reported offsite dose results, although they did not always give the exact time and location where measurements had been taken.

Since State and county officials felt that the threat to the general public was not serious enough to warrant prompt notification through activating the Prompt Notification System. Official information provided to the public via the Emergency Broadcast System (EBS) was delayed. The initial EBS message was broadcast at approximately 12:30 p.m., although the major news media were advised of the situation by State and county PIOs before the EBS messages were broadcast. Eight different EBS messages were issued and aired periodically by the local EBS station during the event. The EBS station was deluged with calls because the official messages did not provide a number to call for additional information. An information number was not provided because government officials did not want to generate calls to which they could not physically respond.

According to the Monroe County PIO, the licensee did not notify county and State PIOs in advance of briefings, nor did the licensee coordinate all new press releases with county and State PIOs.

The media and public received information about the incident prior to any State or local official announcement. This information was released by the National Weather Service (NWS) teletype and radio band. NWS had picked up the information from one of the 159 National Warning System (NAWAS) drops in New York State. NWS then sent the information out on their weather teletype before the general public was notified by the State.

6.3 Federal Agency Response*

The National Radiological Emergency Preparedness/Response Plan for Commercial Nuclear Power Plant Accidents (Master Plan) identified 10 Federal organizations with primary response roles, and delineates the functional responsibilities of each. FEMA alerted each of these agencies that they might be activated for response to the event at Ginna. FEMA also notified 12 other Federal agencies and private organizations about the event. Of the agencies listed in the Master Plan, only three or four Federal agencies were eventually deployed to the scene of the accident. The State did not request further supplemental Federal assistance for the incident.

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*This report was developed by the Federal Emergency Management Agency and coordinated with the other Federal agencies identified in the Master Plan. This report describes operational responses based on a comparison of agencies actions with those prescribed in the Master Plan.

This section is composed of a detailed list of responses made to events at Ginna by each Federal agency notified by and including FEMA.

6.3.1 Federal Emergency Management Agency (FEMA)

(1) Members of FEMA's National Rapid Response Team arrived in Rochester at 3:30 p.m. The team arrived at the scene to monitor the situation and make an impact assessment.

The NRRT worked with NRC and New York State officials. The potential need for additional Federal resources was reviewed.

(2) A FEMA Emergency Support Team was activated in Washington, DC to provide guidance and support for the National Rapid Response Team at the site.

(3) The Deputy Federal Coordinating Officer from the NRRT established a temporary field office in Rochester.

(4) FEMA Region II staff held a meeting in New York City with regional representatives from the Department of Health and Human Services (HHS), the U.S. Department of Agriculture (USDA), the Food and Drug Administration (FDA), and the Environmental Protection Agency (EPA) to brief them on the situation and prepare them for possible deployment. FEMA Region II staff also notified key personnel in the regional offices of the U.S. Department of Transportation (DOT), the Department of Defense (DOD), the National Oceanographic and Atmospheric Administration (NOAA) and the Coast Guard (USCG) of the event.

(5) The Deputy Federal Coordinating Officer's Public Information Officer worked with NRC, State, and County Public Information Officers to ensure that public information releases were coordinated among them for accuracy. FEMA also sent a representative to NRC's Office of Public Affairs to establish initial public affairs liaison.

(6) FEMA's Emergency Information and Coordination Center (EICC) notified the following Federal agencies and the National Communications System (NCS), to be available to provide assistance in response to the event: FEMA, USDA, DOE, USCG, HUD, DOT, NOAA, EPA, GSA, HHS, and DOD.

(7) FEMA's State and Local Programs and Support (SLPS) group dispatched a liaison officer to NRC Headquarters to keep the Emergency Information and Coordination Center (EICC) informed of significant developments.

(8) FEMA notified Canadian authorities of the Ginna event.

(9) FEMA personnel were dispatched to two State EOCs (Albany and Newark), two County EOCs (Wayne and Monroe), and to the Emergency Operations Facility.

(10) FEMA's SLPS Associate Director, and the Chairman of the Nuclear Regulatory Commission agreed to coordinate the activities of their agencies in accordance with the Master Plan and the Memorandum of Understanding between them.

(11) FEMA kept the White House advised of developments.

6.3.2 Nuclear Regulatory Commission (NRC)

(1) NRC coordinated the licensee's response and notified FEMA and other Federal agencies of the events as they developed at the plant. The interaction between NRC and FEMA was undertaken in accordance with the Memorandum of Understanding between NRC and FEMA of October 22, 1980.*

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*Federal Register 45 FR 82713, December 16, 1980.

(2) NRC provided technical advice to State and local officials and participated with FEMA in coordinating activities at the site with State and County officials.

6.3.3 Department of Energy (DOE)

(1) DOE assembled its Emergency Action and Coordination Team after a report of the event was received by the DOE Emergency Operations Center.

(2) DOE's Lawrence Livermore National Laboratory (LLNL) of California assisted New York State officials in their analysis of off-site radiation impact by providing computer predictions of potential dose consequences based on radiological and meteorological data. This assistance was provided from the laboratory in California under pre-existing arrangements with the State of New York.

(3) DOE contacted its radiological team at Brookhaven National Laboratory (BNL) and advised them on the status of events at Ginna.

(4) DOE contacted the NRC Operations Center and BNL to make transportation and other arrangements should a team from DOE be needed to assess the problem at Ginna.

(5) DOE put their teams at BNL and Andrews Air Force Base on initial standby and checked with the USCG on the availability of helicopters for the BNL group.

(6) NRC was advised of DOE's readiness to respond with ground monitoring personnel and equipment (located at BNL) and aerial monitoring resources (located at Andrews Air Force Base).

(7) When it became apparent, about 1:00 p.m., that there were no releases having significant off-site effects, the BNL's readiness condition was terminated. The aerial monitoring capability was maintained at a deployment readiness until NRC and New York State indicated no further need for there resources.

(8) After consulting internally and with New York State, NRC advised at about 3:25 p.m. that DOE would not be requested to provide monitoring or assessment resources at Ginna. At this point, the Andrews Air Force Base resources were returned to their normal readiness condition. At 4:30 p.m. (EST), LLNL assistance to New York State was terminated.

6.3.4 U.S. Department of Agriculture (USDA)

(1) The USDA Regional Emergency Staff Chairperson in New York City attended a meeting held by FEMA on the Ginna event and remained on standby until 20:45 hours.

(2) A USDA County Emergency Board Director was on site at the Civil Defense County Headquarters of Monroe County, remaining there until 20:30 hours.

(3) Key managers within USDA were kept posted on the status of the emergency and informed as additional information was made available.

6.3.5 U.S. Department of Commerce (DOC)

(1) Department of Commerce (Headquarters) was notified by FEMA.

(2) FEMA's Region II office notified NOAA at the regional level and discussed participation of the National Weather Service (NWS) Office at Rochester in events at Ginna.

(3) At 10:12 a.m. (EST) an alert message was received over National Warning System (NAWAS) from the State of New York advising that an alert had been declared at Ginna. This message was immediately carried over the NOAA Weather Radio, word for word, utilizing the 1050-Hz tone alert, as had been agreed to with New York State.

(4) At 10:42 a.m., New York State authorities announced over NAWAS that the release of radioactive steam had terminated. This message was immediately

broadcast over NOAA Weather Radio with the tone alert, word for word as received. The tape of the 10:12 a.m. alert message remained on the air until replaced by the 10:42 a.m. message.

(5) During the late morning and early afternoon of January 25, NWS was asked to coordinate weather forecasts of wind direction, wind speed, and precipitation by two other units providing meteorological support to Rochester Gas and Electric Corporation: the Lawrence Livermore Laboratory of California and meteorologists for the State of New York. The NWS Forecast Office in Buffalo assisted with technical expertise.

(6) NWS Eastern Region Headquarters was advised of the Alert at 10:12 a.m., as soon as NWS was informed. During the day, from approximately 11:00 a.m. through 4:00 p.m., the National Weather Service Office in Rochester was in periodic contact with the Chief of the Meteorological Services Division of NWS Eastern Region Headquarters, for consultation on the role of NWS during the situation.

6.3.6 Department of Defense (DOD)

The Department of Defense was on standby to provide medical and evacuation support, if required.

6.3.7 U.S. Department of Health and Human Services (HHS)

(1) The Bureau of Radiological Health (BRH) of the Food and Drug Administration (FDA) notified FDA Headquarters Office of Executive Director of Regional Operations (FDA-EDRO), pending confirmation of events.

(2) FDA-EDRO notified its Region II office in New York City (FDA-II).

(3) FDA-BRH notified the Public Health Service's (PHS) Emergency Coordinator's Office.

(4) FDA-EDRO notified its Division of Field Investigations.

(5) FDA-EDRO alerted several FDA executives.

(6) FDA-BRH alerted PHS Centers for Disease Control (CDC) following confirmation of events.

(7) FDA-BRH alerted FDA Region II Radiation Representative's Office.

(8) FDA-EDRO notified its Division of Field Science.

(9) FDA-BRH requested and received a technical update from NRC.

6.3.8 U.S. Department of Transportation (DOT)

(1) DOT Headquarters notified the DOT Regional Emergency Transportation Office.

(2) The DOT Regional Emergency Transportation office notified DOT Regions I and II, which in turn notified State transportation officials, the U.S. Coast Guard, and the railroads. This notification of the water and land modes was for the purpose of indicating the possibility of a hazardous situation in the area of the plant. The Regions reported to headquarters available information on transportation activities in the area.

(3) DOT Headquarters notified the Federal Aviation Administration (FAA) to have them take appropriate actions concerning air traffic in the area. FAA called EPA for guidance on whether aircraft should be allowed to fly through the plume. EPA reported it had no "source term information" that would justify that planes be routed away from Ginna.

(4) DOT can not initiate actions on its own initiative. There must be a request for assistance from the State. However, plans were ready for implementation should such requests have come to DOT.

6.3.9 U.S. Environmental Protection Agency (EPA)

(1) EPA was in communication with NRC and DOE to determine, if they should send a team to the Ginna area.

(2) EPA had a mobile laboratory ready to go, orders for personnel, cash available for emergency team use, calibrated instruments packed for the trip, and a plane standing by ready for the advance team. The Eastern Environmental Radiation Facility (EERF) team was placed on standby. The EERF could have responded at the site with an advance team within three (3) hours of notification. The mobile lab could have been there within twenty-four (24) hours.

(3) FAA called EPA for guidance on whether aircraft should be allowed to fly through the plume. EPA had no "source term information" that would justify rerouting aircraft.

(4) EPA contacted New York State officials. New York State officials informed EPA that "the loop had been isolated" and no more releases were expected.

(5) A health physicist in Ontario, Canada, called EPA for a status report as to whether there had been releases to Lake Ontario, or if a release was likely. EPA had no information to indicate that such releases were likely.

(6) EPA called DOE to ascertain DOE's plans to respond. DOE had teams at Brookhaven National Laboratory and Andrews Air Force Base on initial standby and had checked with the U.S. Coast Guard on the availability of helicopters. By 1:30 p.m., they were no longer on standby at Brookhaven for emergency response, but would request EPA to assist in followup monitoring, if needed. EPA asked whether DOE would request EPA to assist in followup monitoring if they responded. DOE was not sure it would have a request from either New York State or NRC to do confirmatory measurements, if such a request was received, DOE's response would have been coordinated with EPA.

(7) EPA did not deploy a monitoring team to Ginna for the Site Area Emergency. EPA was not requested to deploy. EPA judged the situation to be of insufficient severity to warrant deployment without a request from the State or DOE.

(8) EPA reported that information available from NRC was inadequate.* EPA is following up with NRC to ensure more prompt and complete information is transferred.

6.3.10 National Communications System (NCS)

(1) NCS Region II was in contact with NCS Headquarters to discuss possible support that might be required at Ginna.

(2) NCS Headquarters reviewed the data for the area around Ginna to determine what circuits would be available if needed.

(3) The NCS Region II and Headquarters remained on standby until they were notified the plant was under control and in a stable condition.

6.3.11 Department of Housing and Urban Development (HUD)

Although HUD is not a Federal Agency identified in the Master Plan, the HUD Deputy Under Secretary for Field Coordination directed the Regional Administrators for HUD Regions 1, 2, 3, and 5, which adjoin the Ginna Nuclear Power Plant area, to conduct vacancy counts of housing within their States. HUD reviewed its files for vacancies in HUD-insured single and multi-family housing that had been repossessed, as well as in Section-8-assisted and local Public Housing Authority vacancies.

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*Subsequent letter from EPA to NRC dated February 10, 1982, detailed the data EPA required. This specific data was not available to NRC at the time.

6.4 NRC Regional Response

6.4.1 NRC Senior Resident Inspector's Response

The primary functions of the Senior Resident Inspector as specified in the NRC Region I Incident Response Supplement are as follows: (1) assist the regional and NRC Headquarters personnel in the initial assessment of an event, (2) ensure that appropriate NRC managerial personnel are informed of the details of any incident, (3) verify the accuracy of information provided by the licensee to NRC, (4) provide assistance in the evaluation of the licensee's response to the incident, (5) monitor adherence to requirements, and (6) make independent measurements or observations as directed. The SRI had been issued, and had available on the day of the event, a copy of the NRC memorandum on actions to be taken by the Senior Resident Inspector during an event.

At approximately 9:33 a.m., the licensee notified the NRC Headquarters' Duty Officer of the event by Emergency Notification System telephone. The Senior Resident Inspector at Ginna noticed the Emergency Notification System circuit light on his phone, picked it up and monitored the licensee's report. He proceeded directly to the control room at 9:35 a.m., where he remained until 1:48 p.m.

When the Senior Resident Inspector first arrived in the control room, he was briefed on the status of the event by the Operations Engineer and noted that the Emergency Notification System (ENS) telephone was being manned. The Senior Resident Inspector positioned himself between the ENS telephone and the important sections of the control panel, so that he could directly observe the emergency core cooling system (ECCS) and other critical primary plant parameters, and verify that automatic safety injection equipment had started and was operating. As important information became available, the Senior Resident Inspector ensured that it was transmitted to NRC over the ENS. Although the Senior Resident Inspector had not been informed that the Regional Incident Response Center (IRC) had been activated, he felt assured that NRC regional management was aware of the event.

The Senior Resident Inspector communicated periodically with NRC regional and headquarters teams over the Emergency Notification System telephone, although he had difficulty hearing headquarters personnel. He decided to use a commercial telephone line to the Regional Incident Response Center (IRC) and to keep that line open. This telephone call was made directly to Region I and did not include the Headquarters Operations Center. The open line allowed him to gather information, evaluate plant status, and then make reports to the regional IRC while the licensee responded to specific information requests. Initially, the Senior Resident Inspector had difficulty obtaining the commercial line.

The NRC Region I Base Team asked the Senior Resident Inspector to verify which procedures were being used by the licensee. The Senior Resident Inspector observed that procedures for steam generator tube rupture and a small-break loss-of-coolant accident were in use in the control room.

The Senior Resident Inspector received two calls on a different phone in the control room. Both calls were from the Duty Officer at NRC Headquarters (NRC:HQ), who asked the Senior Resident Inspector to wait because the Director of the NRC Office of Inspection and Enforcement wanted to talk to him. After waiting 3 to 4 minutes the Senior Resident Inspector hung up because events in the control room required his attention; he then informed the regional Incident Response Center that the Director of Inspection and Enforcement was trying to reach him. The Senior Resident Inspector later responded directly to the NRC Chairman, who requested information about plant status, and who asked about the Resident Inspector's perception of the event and of the licensee's actions. The Senior Resident Inspector was in the control room when the licensee upgraded the emergency classification to an Alert (at 9:40 a.m.) and to a Site Area Emergency (at 10:44 a.m.).

Information between the licensee, Senior Resident Inspector, and the NRC was handled through both the Emergency Notification System telephone and an open commercial telephone in the control room. Information requests from NRC Headquarters and the NRC Region I Office were transmitted to the licensee on the Emergency Notification System telephone and then relayed to the operating crew, the Technical Support Center, and the Senior Resident Inspector.

The Senior Resident Inspector determined that the Region I Base Team was receiving health physics data from the licensee. The Region I Base Team notified the Senior Resident Inspector that the Site Team had been dispatched, reported its composition, and asked him to inform the licensee of who would be arriving and of the approximate time of their arrival. They also told the Senior Resident Inspector that Resident Inspectors from FitzPatrick and Nine Mile Point had been dispatched to Ginna.

The Senior Resident Inspector was the sole NRC presence at Ginna until the two inspectors from FitzPatrick and Nine Mile Point arrived at approximately 2:00 p.m. When they arrived, they were taken to the Technical Support Center where they were briefed and assigned duties by the Senior Resident Inspector. He then returned to the control room to continue monitoring events.

At 3:17 p.m., the Senior Resident Inspector went to the Technical Support Center to gather information on the licensee's recovery plans. The Senior Resident Inspector attended the Plant Operations Review Committee (PORC) meeting at 3:30 p.m., which was held to discuss events and plans for recovery. He subsequently attended most PORC meetings held by the licensee.

After the arrival of the NRC Site Team at approximately 4:15 p.m., the Senior Resident Inspector gave an initial briefing to the Site Team Leader (STL) and the Reactor Safety Coordinator (RSC). From then on, the STL was in charge of NRC's response at the site. The Senior Resident Inspector then reported directly to the RSC. Following departure of the RSC later that afternoon, he reported directly to the Technical Support Coordinator.

6.4.2 NRC Regional Office Response

6.4.2.1 Regional Emergency Response Plan*

The concepts of this plan are included in the Region I Incident Response Supplement, which defines the Base Team, Site Team, and response modes. Table 6.1 outlines the composition of the Base Team and the Site Team for this event.

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*Based on NRC's "Report to Congress: NRC Incident Response Plan" (NUREG-0728), September 1980.

The Site Team is normally deployed in two stages: the Advance Team and the Backup Team. The Advance Team consists of the Site Team Leader/Director of Site Operations, Protective Measures Coordinator, Reactor Safety Coordinator, Technical Support Coordinator, Emergency Response Coordinator, Public Affairs Coordinator, the State Liaison Officer, and includes the Senior Resident Inspector at the site. The Backup Team is made up of the remaining positions shown in Table 6.1.

The Base Team serves as a short-term incident control center in conjunction with NRC Headquarters while a Site Team is enroute to an incident. The Base Team functions to provide expedited contact between the involved licensee and NRC regional personnel so that NRC incident response objectives can be achieved. It is activated at the direction of the NRC Regional Administrator.

The Site Team functions under the direction of the Regional Administrator who may eventually be designated as the Director of Site Operations (DSO). As DSO, the Regional Administrator becomes the focal point for NRC response and is responsible for directing all onsite technical aspects of the Federal response to the incident. The location of various individuals in the Site Team may vary on a site-specific basis.

6.4.2.2 Actions of the NRC Regional Office in Response to the Event

At 9:38 a.m., the NRC Headquarters Duty Officer called the Region I Director of the Division of Project and Resident Programs on a Federal Telecommunications System (FTS) line about events at Ginna. Based on the initial information provided, a phone bridge was set up over the Emergency Notification System (ENS) and FTS line linking Ginna, the NRC Headquarters Duty Officer, and the Division Director, who had called in his two Branch Chiefs. At 9:45 a.m. they were told that the licensee had declared an Alert at Ginna. The Division Director then went to the Regional Administrator's Office and recommended that the Regional Incident Response Center (IRC) be activated.

The Regional Administrator concurred, and contacted the Deputy Executive Director for Regional Operations and Generic Requirements, at NRC Headquarters

Table 6.1 Composition of NRC regional response teams

BASE TEAM

Emergency title	Before departure of site team	After departure of site team
Base Team Manager	Regional Administrator	Deputy Regional Administrator
Regional Public Affairs Manager	Public Affairs Officer	Field Public Affairs Officer
Operational Assessment Manager	Director of Division of Project and Resident Programs	Reactor Projects No. 1, Chief
Radiological Assessment Manager	Facilities Radiation Protection Section Chief	Director of Division of Emergency Preparedness and Operational Support
Logistical Support Manager	Emergency Preparedness and Program Support Branch Chief	Emergency Preparedness and Program Support Branch Chief
Administrative Manager	Administrative Branch Chief	Administrative Branch Chief
Communications Manager	Independent Measurements and Environmental Monitoring Chief	Materials Licensing Section Chief

* Was regional State Liaison Officer before current position.

SITE TEAM

Emergency title	Regional title
Site Team Leader/Director of Site Operations	Regional Administrator
Reactor Safety Coordinator	Director of Division of Project and Resident Programs
Technical Support Coordinator/Operations Team Leader	Reactor Projects Branch No. 2 Chief
Senior Resident Inspector	Senior Resident Inspector
System Specialists (3)	Reactor Projects Inspectors (2) Indian Point Section Chief
Protective Measures Coordinator	Facilities Radiation Protection Section Chief
Health Physicists (4)	Radiation Specialists
Environmental Team Leader	Independent Measurements and Environmental Monitoring Section Chief
Emergency Response Coordinator	Radiation Specialist
Inplant Team Leader	Radiation Specialist
Public Affairs Coordinator	Public Affairs Officer
State Liaison Officer	Reactor Projects Section No. 1B Chief*

to apprise him of the event and request that the NRC Headquarters Emergency Team be put on standby. The Regional Administrator also contacted the Director of the Regional Division of Emergency Preparedness and Operational Support to ensure that the Incident Response Center was set up and the appropriate people notified.

The Region I Emergency Notification System (ENS) communicator's first attempt to contact the NRC Headquarters Duty Officer using the ENS extension in the Incident Response Center was unsuccessful. (Instructions for how to use the ENS were not available near the phone.) The communicator then used a regular commercial line to call the NRC Headquarters Duty Officer and requested that he be bridged into Ginna through the ENS.

Following a public address anouncement to activate the Regional Incident Response Center at approximately 9:50 a.m., the Incident Response Center was put into the configuration shown in Figure 6.3. Region I does not have a dedicated Incident Response Center, but uses the region's conference room after moving the tables into new positions. By 9:55 a.m. the Incident Response Center was fully staffed and in contact with the site using both the Health Physics Network (HPN) and the Emergency Notification System. The New York State Liaison Office and Department of Health were contacted at 10:00 a.m., advised of the Alert, and updated on the current plant status. The Communications Manager had notified the Regional Director for Region II of the Federal Emergency Management Agency (FEMA) at 10:08 a.m. that an Alert had been declared at Ginna.

On activation of the Regional Incident Response Center, the Director of the Division of Project and Resident Programs briefed the Base Team Manager and the support staff on the current situation and on the events that had occurred up to that time.

As indicated in the Regional Incident Response Center log, the power-operated relief valve (PORV) on the pressurizer had stuck open, and at 10:16 a.m. the region was notified that the pressurizer level had gone from offscale low to offscale high, indicating a full pressurizer and the probable presence of a steam void in the reactor vessel. These events actually occurred at 10:09 a.m.

and 10:11 a.m., respectively. The time recorded in the regional log corresponds to the time when Region I was notified, not the time the event occurred. The Senior Resident Inspector became aware that a steam bubble had formed in the reactor vessel head shortly after it was recognized by the licensee. This information was communicated over the Emergency Notification System (ENS) phone to the regional office. A Region I ENS communicator received the information, stated that the reactor had a steam bubble in the vessel, but he did not record this information in the log. From 10:31 a.m. until it became apparent that the steam bubble had been reestablished in the pressurizer, the regional log indicates that the reactor head and core temperatures were monitored and regularly reported to the Incident Response Center by the licensee.

Shortly before 10:30 a.m., the Region I Administrator decided that a Site Team should be chosen and dispatched, and requested that the Director of the Office of Inspection and Enforcement activate the Executive Team (ET). The Administrator of Region I, after evaluating the status of events, selected members for the Site Team with backgrounds appropriate to the situation.

When the Site Area Emergency was declared, this information was relayed by the Base Team to the New York State Department of Health and the Federal Emergency Management Agency (FEMA) at 11:25 a.m. At 11:40 a.m., the Site Team left the Region I Office for the Philadelphia airport.

When the initial message was issued over the public address system to activate the Incident Response Center (at approximately 9:50 a.m.), the Administrative Manager started making travel arrangements with a private airline about the availability of helicopters. The airline notified the region that it could not fly to Rochester because of bad weather in the Rochester area. The Site Team Leader opted to take the first available commercial flight, since one was scheduled to leave Philadelphia at 1:00 p.m. and arrive in Rochester at 2:00 p.m. This flight would get the nine-person response team there in less time than a helicopter or small plane would take.

While the Site Team prepared for departure, a member of the NRC Region I Safeguards Section contacted security people at the site to set up transportation from the Rochester airport to the Ginna site. The site security people arranged a police escort to accompany the Team from the airport to Ginna.

The Site Team left for the Philadelphia airport by car around 11:40 a.m. Although they did not have a police escort and encountered minor traffic congestion, they arrived at the airport approximately 15 minutes before the flight was scheduled to depart. (The flight had been delayed in Philadelphia approximately an hour, apparently because of bad weather in Rochester.) While at the Philadelphia airport, the Site Team members called back to their counterparts in the regional IRC to obtain the latest information on the plant status. The Site Team Leader briefed the team at the airport, but the Public Affairs Coordinator was not present. During this briefing, the Site Team Leader determined that the steam void had been reestablished in the pressurizer.

The Team arrived at the Rochester airport at approximately 3:15 p.m., and again called the regional Incident Response Center for an update on the status of the event. Before leaving the Rochester airport, the Site Team Leader was interviewed by a Rochester TV station. Once the Team assembled its equipment, it went by van (provided by the licensee) to the site accompanied by a police escort. Weather conditions during the drive were extremely poor because of wind-driven snow and icing.

While the Site Team was in transit, the Base Team continued to monitor the status of the plant and of radiological measurements being taken offsite. By the time the Site Team arrived in Rochester, the Backup Team had also departed for Ginna, and arrangements were being made to send the regional radiation measurements van to the site. The Backup Team arrived in Rochester around 6:00 p.m. and, after calling the Site Team, was told to report to the site at 4:00 a.m. on January 26.

With the exception of the State Liaison Officer (SLO), who went to the Emergency Operations Facility (EOF), the entire Site Team initially went to the Technical Support Center (TSC). Upon their arrival, they were initially provided a quick briefing by the Senior Resident Inspector and then a more detailed briefing by the Plant Superintendent. At approximately 5:00 p.m., the Site Team Leader

(STL) called NRC Headquarters and spoke with the Acting Director of the Executive Team. The official transfer of authority was then made and the STL became the Director of Site Operations (DSO) with full authority for the NRC response. The DSO notified FEMA of this transfer of authority. After the initial briefings in the Technical Support Center, the Environmental Team Leader (ETL), a member of the Site Team, left to assess the offsite radiological measurements which had been conducted by the licensee and the governmental agencies.

The teams took the following equipment to the site on January 25: 13 radiation monitoring instruments, four air samplers, a SAM-2 portable assay meter for detecting radioiodines, 11 hand-held radios, a radio repeater with base antennae and cable, charcoal cartridges, self-reading pocket dosimeters, radio battery chargers, and two radio telephones. Although the NRC team made no offsite dose rate measurements, it did recount all samples collected by the licensee to confirm the licensee's measurements. NRC's thermoluminescent dosimeters were exchanged on Wednesday, January 27, after the team was satisfied that there could be no additional releases and that the reactor was in cold shutdown.

From 4:30 p.m. on, the Site Team Leader attended the Plant Operations Review Committee (PORC) meetings which discussed recovery operations. During one of these meetings, the licensee decided to downgrade the event to an Alert (at 7:17 p.m.), a decision with which the Director of Site Operations and Site Team concurred. Later, the Director of Site Operations and the Reactor Safety Coordinator discussed with the licensee the criteria and basis for further downgrading of the event. Subsequently, at 10:45 a.m. on January 26, the licensee made the decision to downgrade the event to the Recovery phase, a decision with which the Director of Site Operations concurred.

In discussions between the DSO and Base Team Manager after the plant status had been downgraded to an Alert, the decision was reached to reduce the Base Team to include only the Radiological Assessment Manager and the Operations Assessment Manager. The reduced staff was maintained until the Site Team was deactivated at 4:00 p.m. on January 26.

After discussing the plant status on the evening of January 26th with the Site Team members, NRC:HQ, and the Base Team, the Director of Site Operations decided to deactivate the NRC emergency response team. After subsequent discussions with FEMA, both agencies deactivated their response teams.

6.4.2.3 Information Flow and Assessment Within the Base Team

After initial setup of the Region I Incident Response Center (IRC), which took approximately 10 minutes, operations and health physics personnel manned the Emergency Notification System and Health Physics Network and phones, although at times the noise level in the IRC made it difficult to hear NRC Headquarters personnel. IRC personnel logged information received from the site on regular note paper, although the regional IRC did have special incident message forms available. Only the Communications Manager used these forms, however.

To keep the Regional Public Affairs Manager (RPAM) apprised of events, a Senior Resident Inspector (visiting the Regional Office and knowledgeable about pressurized water reactors) was assigned to brief personnel dealing with the press. Midway through the first day, this method was discontinued, making it necessary for the RPAM to obtain information directly from the Incident Response Center.

When the regional Incident Response Center was initially activated, both the Regional and the Public Affairs Coordinator (PAC), who would be sent to the site, were briefed by the Base Team Manager on initial conditions at the site. After this briefing, the RPAM contacted the NRC: Headquarters Office of Public Affairs and opened a line from them to the licensee which remained open for approximately 45 minutes.

Gaps in communicating information to the Regional Public Affairs Manager occurred on the first day. He was not told that a steam bubble had been created beneath the reactor vessel head. However, during this period, he was told that fuel temperatures indicated that the fuel was not overheating. The RPAM's log for 11:30 a.m. stated that water had overflowed to the containment floor when, in fact, it had overflowed to the building sump.

Operational data on plant conditions were gathered from Emergency Notification System (ENS) communicators. Base Team members wanting operational information had requests channeled through the Operations Assessment Manager, who orally requested the information from an ENS communicator, that is, requests were not written. This system was also used for the Health Physics Network (HPN) phone. Message logs maintained by both the HPN and ENS communicators were not copied for distribution among members of the Base Team.

Major assessment actions undertaken by the Base Team included the verification that natural circulation existed in the A loop after both reactor coolant pumps were tripped, and the B steam generator was isolated. In order to do this, the Base Team requested that the licensee's ENS communicator report T_{COLD} and T_{HOT} temperatures in the A and B loops, reactor coolant system (RCS) pressure, and RCS subcooling.

The licensee's communicator reported T_{COLD} for the A and B loops and core exit thermocouple temperatures in place of T_{HOT} because the plant does not have installed T_{HOT} meters. For reactor coolant system subcooling, the licensee's communicator provided both calculated values and values indicated on the subcooling monitors. The calculated subcooling values were almost double the values indicated, causing both the licensee's communicator and the Base Team to believe that the meters were not working properly. As discussed in Chapter 4 of this report, the meter's design caused the discrepancy between the values calculated and those indicated. Neither the Base Team nor, apparently, the licensee's communicator were aware of the cause of the discrepancy.

Based upon information reported by the licensee, the Region I Base Team was unable to independently verify the existence of natural circulation. The reported T_{COLD} and core exit thermocouple temperatures presented an anomaly to the Base Team in that they indicated that the B loop T_{COLD} was colder than the A loop indication, despite the fact that it was known that the plant cooldown was proceeding by use of A steam generator. Also the reported core exit thermocouple temperatures were less than the A loop T_{COLD} temperatures and the trend of the core exit reading was such that temperatures were increasing over time. The apparent inconsistency in these temperature readings caused the Base

[redacted]

Team to question the existence of natural circulation, although they did not specifically address their concerns to licensee management until safety injection was terminated. After safety injection was terminated, the Director, Division of Project and Resident Programs discussed the Incident Response Center's concern with the Ginna Operations Engineer who was in the control room. The Operations Engineer was not able to specifically address the NRC concern and directed NRC to contact the Technical Support Center (TSC). This was done and the Region I Base Team was placed in direct communication with the Plant Superintendent. The Base Team requested the Plant Superintendent to justify securing safety injection while the existence of a steam bubble in the reactor vessel head was suspected and natural circulation had not been verified. NRC's concern was never completely resolved. The need for resolution subsided as a single safety injection pump was started followed by the restart of the A reactor coolant pump.

6.4.2.4 Information Flow and Assessment Within the Site Team

With the exception of the State Liaison Officer (SLO), the team proceeded to the TSC from Rochester. The SLO talked to representatives from the State of New York, Wayne and Monroe Counties, and the Federal Emergency Management Agency in the Emergency Operations Facility. They all told him that they were satisfied with the information that they had been given. Since the Public Affairs Coordinator (PAC) had gone to the site, the SLO went to the Public Information Center (PIC) in the basement of the licensee's headquarters. The SLO had two telephone numbers for the Senior Resident Inspector and attempted to contact the site using these numbers, but it was very difficult to get through. In fact, the State Liaison Officer could obtain information more quickly by calling the Regional Public Affairs Manager at the Region I Office.

The major concern of the press was the duration of the release. When the SLO tried to obtain this information from the Emergency Operations Facility, he found that the licensee lacked complete information for the period before the EOF was activated. The SLO was able to get the necessary information on release duration from Region I.

Although the Director of Site Operations had no problems making calls from the Technical Support Center, commercial calls made from the Resident Inspector's Office while someone else was on the Health Physics Network (HPN) phone terminated the HPN connection. In addition, news inquiries from the press came to the Resident Inspector's Office since his, rather than the Ginna plant phone number, is listed in the Rochester telephone directory. These phone calls were promptly referred to public affairs personnel at either the Public Affairs Center or NRC Headquarters.

Although the NRC Site Team was in the Technical Support Center, they were not always aware of information requests made of the licensee by NRC Headquarters and Regional Base Team staff. This resulted because these NRC staff members occasionally talked directly to the licensee through the Emergency Notification System plant communicator.

Around 11:30 p.m. the DSO left the site for his hotel where he received update briefings from both the site and Emergency Operations Facility throughout the night.

Since the steam bubble was re-established in the pressurizer before the Site Team arrived, their major responsibilities involved determining the amount of radioactivity released, preparing an event chronology, and reviewing recovery actions and de-escalation criteria. The Director of Site Operations assigned personnel to perform these functions, and a schedule for 24-hour coverage was prepared.

The Public Affairs Coordinator remained with the Site Team Leader and gathered information by listening to his conversations with other team members and licensee personnel. Licensee operators in the Technical Support Center placed calls for the Public Affairs Coordinator to the Public Affairs Center and the Regional Public Affairs Manager.

At approximately 8:45 p.m., after the event had been downgraded to an Alert, the Public Affairs Coordinator (PAC) left the Technical Support Center for the Public Information Center (PIC). He stated that he went to the PIC because the level of activity at the site had subsided. Since the PAC was at the site and the State Liaison Officer (SLO) was in the Public Information Center, no NRC personnel were in the Emergency Operations Facility, although the SLO could quickly return if contacted.

On the morning of January 26, the NRC backup team arrived at the site and in conjunction with the Senior Resident Inspector prepared a chronology of events, which was provided to the licensee's staff for their information and which was transmitted to Region I and NRC Headquarters. Process computer output and copies of control room strip charts were collected during the night and had been used to develop the chronology. The chronology specifically stated that a steam bubble in the reactor vessel was first indicated at 10:09 a.m. The Public Affairs Coordinator did not receive this chronology until after he learned about it from the Regional Public Affairs Manager in the regional office, whereupon he called the site to request that a copy be sent to him.

6.4.2.5 Use of Procedures

A draft set of response procedures had been prepared by the NRC Regional Office in December 1981. Although these procedures were still in draft form and had not yet been formally approved, they were available to the members of both the Site and Base Teams. The response of both the Site and Base Teams was event-specific, and primarily involved an independent evaluation of the event and verification that the licensee's personnel were taking appropriate actions.

6.5 Headquarters Response Organization

This section describes the response made by NRC's Headquarters emergency response organizations activated during the Ginna event. The current configuration of these organizations is described in "Report to Congress: NRC Incident Response Plan" (NUREG-0728). At the time of the Ginna event, the final draft of "Agency Procedures for The Incident Response Plan" (NUREG-0845) was undergoing final review. The Headquarters response to the Ginna event is described in terms of procedures which were in effect at that time.

The Headquarters Operations Center response to the Ginna event began at 9:33 a.m. when the Ginna Shift Supervisor made his initial notification to the Operations Center on the Emergency Notification System. He reported an Unusual Event involving a steam generator tube rupture which had occurred at 9:25 a.m. This notification initiated a series of actions at the NRC Headquarters Operations Center that would require some augmented staffing for the next 31½ hours.

6.5.1 Headquarters Duty Officer

The position of Headquarters Duty Officer is occupied on a rotational schedule by technically qualified individuals drawn from various NRC staff offices. The Duty Officer who received the initial notification of the Ginna event was on temporary assignment to NRC's Office of Inspection and Enforcement (IE) from the Office of Nuclear Regulatory Research (RES). He was serving the last day of a seven-day assignment, and was, therefore, familiar with operation of the communications equipment and with the NRC Headquarter's procedures for receiving event notification. After receiving initial notification of the event from the Ginna Shift Supervisor, his attempt to follow the Operations Center Procedures conflicted with the shift supervisor's need to return to the control room and direct responses to the event. Subsequently, another individual became the communicator for the licensee and provided the requested information. At 9:38 a.m., after receiving the recommendation from the licensee's communicator to maintain the open Emergency Notification System line between the plant and NRC Headquarters, the Duty Officer set up a conference call on phone Bridge No. 2 between the plant, NRC Region I (on the Federal Telecommunications System), and Headquarters. After completing this procedure, the Acting Chief of the Events Analysis Branch was notified at 9:44 a.m. of the situation at Ginna. He immediately came to the Operations Center, bringing with him a member of his staff knowledgeable about Westinghouse facilities. Shortly after reviewing the situation with the Duty Officer and monitoring the conversation between Region I and the plant, he contacted the Director, Division of Engineering and Quality Assurance, and the Chief, Engineering and Technical Support Branch, both of whom reported immediately to the Operations Center. The Duty Officer then notified the Office of Nuclear Reactor Regulation (NRR) of the event, and at 9:49 a.m., he notified the FEMA Operations Center that an Unusual Event had been declared.

At 9:53 a.m., the Region I Incident Response Center called the HQ Duty Officer on a Federal Telecommunications System line and asked that Region I be bridged into the Ginna Emergency Notification System (ENS). The HQ Duty Officer was confused by this request because he knew Region I was already bridged to the Ginna plant. He then realized that he was being asked to add Region I's Incident Response Center (IRC) to the bridge.

NRC Region I had activated its Incident Response Center at 9:52 a.m. Personnel from IE Headquarters had congregated in the Headquarters Operations Center and were monitoring the ENS bridge conversation between Region I and Ginna.

At 10:29 a.m., the Director of NRC's Office of Public Affairs called the Duty Officer and was told that the Operations Center was about to be activated. At 10:30 a.m., NRC Headquarters was notified that Ginna had declared an Alert.

At 10:34 a.m., a member of the Response Coordination Team (RCT) notified the Federal Emergency Management Agency that the NRC Operations Center was being activated. At this point, the Duty Officer assumed the Alternate Duty Officer role and terminated his involvement with the Ginna event.

6.5.2 Response Coordination Team

Members of the Response Coordination Team assumed responsibility for operating the communications system and preparing the NRC Operations Center to respond to the event when the Operations Center was activated at 10:30 a.m. On the morning of the incident, the NRC Operations Center was being painted. The painting crew was asked to leave, the furniture was rearranged, and appropriate resources for the response were provided. (Layout of the Operations Center is shown in Figure 6.4.)

The Response Coordination Team consisted of all members of the Incident Response Branch and was supplemented by personnel from the Telecommunications Branch.

Procedures for the Response Coordination Team (RCT) for Initial Activation Mode require that they:

(1) Activate the the Headquarters Operations Center

(2) Make notification calls

(3) Gather and disseminate information to the Environmental, Technical, and Liaison Teams

(4) Monitor equipment operation, and

(5) Support Headquarters response teams.

In complying with these procedures, the RCT encountered a number of problems. The Director of the RCT was on emergency leave on the day of the Ginna event and members of the RCT selected an Alternate Director and carried out the procedures listed above, except for notification of the Commissioners' Assistants. The RCT erred by delaying notification of the Commissioners' Assistants, a mistake that went unnoticed until almost an hour after the Center was activated. This was further aggravated when the RCT notified the Chairman's Office at 11:46 a.m., and the Chairman's secretary, rather than the RCT, notified the other Commissioners' Assistants.

6.5.3 Headquarters Emergency Officer

The Headquarters Emergency Officer (EO) functions only when the Operations Center is in the normal mode and only during nonduty hours. During duty hours the Duty Officer's procedures list individuals within IE to be called in place of the Emergency Officer. The EO's responsibilities are to ensure that events are properly classified, to determine the appropriate response mode, and to ensure that initial notifications are made.

The Director, Division of Engineering and Quality Assurance came to the Operations Center shortly before 10:00 a.m. and assumed the responsibilities of the

Emergency Officer. Calls were made to begin manning the Operations Center and the assembled staff monitored the conversations between NRC Region I and the licensee. The Health Physics Network (HPN) was not monitored until activation of the Operations Center. This delayed notification of NRC Headquarters of the declaration the Site Area Emergency. NRC Region I was informed of this declaration over the HPN.

At 10:28 a.m., the Headquarters Operations Center was formally activated on orders of the NRC Executive Director for Operations (EDO) and Director, IE, on the recommendation from the Region I Administrator and the Director of Engineering and Quality Assurance, NRC Headquarters. At 10:35 a.m. the Chairman's Office was notified of the activation order by the EDO and Director of the Office of Inspection and Enforcement. At this time the Executive Team assumed responsibility for the NRC response.

6.5.4 Executive Team

When activated, the Executive Team (ET) was composed of a Director (Chairman of the NRC), a Deputy Director (the EDO), and two other members (the Directors of the Office of Nuclear Reactor Regulation and Inspection and Enforcement). NRC's Director of the Office of Nuclear Material Safety and Safeguards (NMSS) is ordinarily the third team member. He was notified and sent a representative from NMSS to the Operations Center.

After gathering in the Executive Team Room (Figure 6.5), Team members participated with the Team Director in deciding the appropriate level of the NRC response, in evaluating licensee actions, and in maintaining liaison with appropriate organizations and individuals. They made recommendations that no protective activities were necessary for the public.

At the time of the initial notification by the licensee, the Director of Inspection and Enforcement, who is the Executive Team member usually closest to the Operations Center during duty hours, was at the Office of the Director of Nuclear Reactor Regulation (NRR). Therefore, the Deputy Director of IE assumed temporary responsibility for Executive Team functions. The EDO had notified the Chairman of NRC at 10:35 a.m. The Directors of IE and NRR had been informed of the developing situation by the Region I Administrator and travelled together to the Operations Center.

At 10:44 a.m., the licensee declared a Site Area Emergency and reported this to the NRC Region I using the Health Physics Network, which NRC Headquarters was not monitoring at this time. This information was transmitted to NRC Headquarters at 10:59 a.m. by the Region I Administrator during a conversation with the Executive Team members present in the Operations Center. The conversation focused mainly on details about the status of the plant.

At 11:25 a.m., the Chairman arrived at the Operations Center, received a status briefing by the Executive Team (ET) members and began carrying out the duties of the Director of the Executive Team. The Executive Team, now fully manned, remained at the Operations Center until 3:25 p.m. when the Director appointed the Executive Director for Operations as Acting Director and left the Center.

At 11:55 a.m., the Executive Team Director contacted the Governor of New York and briefed him on the situation at Ginna. The Governor was subsequently updated at 1:30 p.m. In his first conversation with the Governor, the Chairman discussed the preliminary information known to NRC concerning the tube rupture. He then characterized the release of radiation to be the result of a pressure relief valve that opened for two minutes. He also stated that radiation levels of about 10 millirems per hour had been measured onsite about 400 meters from the plant. The Chairman also reported that the plant was being cooled at that time with no difficulty.

In their second conversation, the Chairman updated the Governor on conditions at the plant (which continued to cool), and included the report that there was no indication of fuel damage based on coolant samples. He further stated that small offsite releases of noble gases in the realm of one millirem per hour had been measured, but that no offsite readings were above background; that NRC had been depending entirely on the licensee readings offsite because it was NRC's understanding that the State of New York was not making any measurements. The Chairman stated he had no reason to doubt the licensee's data, but felt it

[redacted]

would be desirable for the State to make confirmatory measurements. The Governor agreed and stated he would find out whether the State was making measurements since it had the capacity to do so. The Chairman reiterated that he had no reason to disbelieve the licensee's data, but confirmatory data from the State would be appreciated. He added that once the NRC team arrived at the site, they would have the capability to do the offsite confirmatory measurements.

At 1:52 p.m., a representative of the State of New York's Radiological Health Department called the Chairman in response to his previous conversations with the Governor. He reported that the State had no field monitoring teams and, since the release had terminated anyway, such deployment would be futile. He did offer to remove and read the State TLDs, an action which was subsequently performed by the state police. It should be noted that Monroe County officials had monitoring teams conducting surveys offsite, but apparently neither the Chairman nor the New York State health official were aware of this during their conversation.

At 5:00 p.m., the Acting Director of the Executive Team, after briefing the Regional Administrator (who was now at the plant), appointed him to be the Director of Site Operations (DSO) with full authority to act for NRC. The deliberative functions of the Executive Team ceased at this time. The Headquarters teams continued to be apprised of events in order to support the DSO. Between 5:10 and 5:40 p.m., the Chairman, the Governor of New York, other NRC Commissioners, and other Federal agencies were notified of the transfer of authority to the DSO.

6.5.5 Status Officer

During the period of initial activation, the Status Officer made contact and maintained liaison with key Federal officials. Between 11:25 and 11:50 a.m. initial notifications were made to DOE, HHS, EPA, and the White House Situation Room. The Status Officer remained in the Executive Team Room throughout the day, completing additional Information Summaries when significant changes occurred, and updating Federal agencies as appropriate.

After the Director of Site Operations was appointed at 5:00 p.m., the Status Officer so informed HHS, EPA, DOE, FAA (FAA was not on the original notification list, but had made contact with the Operations Center during the day) and the White House Situation Room. At 3:30 p.m., the Radiological Assistance Team at Brookhaven and Aerial Radiological Measurements System at Andrews Air Force Base were released from Standby. After notification of the Commissioners' Assistants was made, the Status Officer function was disbanded after 6:00 p.m.

6.5.6 Protective Measures Analysis Team

The Protective Measures Analysis Team was made up of technical representatives from various Headquarters offices and included a Director, Deputy Director, and individuals with specialties in effluent control, source term, dose assessment, meteorology, hydrology, and health physics.

The Protective Measures Analysis Team monitored the Health Physics Network, and projected radiological consequences. Based on their evaluation of radiological consequences, the team made no recommendations that protective actions were necessary for the public. During this period, the Protective Measures Analysis Team provided radiological assessments to the Executive Team. There was no direct communication of assessments among the Protective Measures Analysis Team, the Region I Base Team, and the Site Team.

The full team remained at the Center until the event was downgraded from a Site Area Emergency to an Alert, whereupon a small support team remained available through the night to support the Director of Site Operations from Headquarters, as necessary.

6.5.7 Reactor Safety Analysis Team

The Reactor Safety Analysis Team consisted of a Team Director, Deputy Director, and staff personnel with various technical specialties in containment structure, core physics, instrumentation and control, and electrical, mechanical, structural, materials, and heat transfer disciplines. Members of this team were drawn from organizations throughout NRC.

The Team monitored the Emergency Notification System and projected event consequences based on the operational conditions of the plant. Based on their evaluations throughout the event, the Team made no recommendation that protective actions were necessary for the public. During this period, the Reactor Safety Analysis Team provided assessments to the Executive Team. There was no direct communication of assessments among the Reactor Safety Analysis Team, the Region I Base Team and Site Team.

6.5.8 Current Status Team

Procedures in the NRC Headquarters Incident Response Plan require that the Current Status Team, once activated, act as the central point of contact with the plant to collect and disseminate information related to an event. The Current Status Team consisted of a Director, Deputy Director, two external communicators (one with a reactor systems background for the Emergency Notification System, and the other with a health physics background for the HPN), two internal communicators who assist the external communicators with information flow to the other teams, and two status-board operators.

The Emergency Notification System phones were monitored by team members starting at approximately 9:45 a.m., although the Operations Center had not been activated. Because of the delay in activating the Headquarters Operations Center, the Region I Incident Response Center was the major NRC participant in these conversations with the plant. After the Current Status Team was activated, they and Region I communicated jointly with the plant. The Team communicator requested specific information as it was needed by other Headquarters Teams.

The Health Physics Network lines in Headquarters were not activated until 11:10 a.m. because the external communicator did not arrive in the Operations Center until shortly after 11:00 a.m.

The full team manned the Operations Center until the event was downgraded from the Site Area Emergency, and a standby team remained through the night to support the Director of Site Operations from Headquarters.

6.5.9 Telecommunications

During the event information was exchanged among the NRC Headquarters Operations Center, the Region I Incident Response Center, the Ginna control room and the Ginna Technical Support Center. The Emergency Notification System (ENS), Health Physics Notification (HPN), commercial and Federal Telecommunications System (FTS) circuits were utilized as the telecommunication links among these organizations. Users reported that the quality of transmission over the HPN, FTS, and commercial lines was adequate. However, the quality of the ENS connections was reported to be marginally acceptable. Operations-related information was reported from the control room and the Technical Support Center over the ENS circuit to the NRC Headquarters Operations Center; and from there, it was bridged over the FTS to the Region I IRC and the Region I Office of the Director, Division of Project and Resident Programs.

The volume on these ENS and FTS lines was low in relationship to the volume of background noise present in the Region I Incident Response Center, the control room, and Technical Support Center. In addition, midband frequency noise was present continuously over the line. Several instances of a steady high pitch tone were also observed. Cumulatively, the high pitch tone disabled communications completely for about two minutes throughout the event. Several times the line was broken for no apparent reason on January 25: at 2:47 p.m. (for seven minutes), 5:50 p.m. (for ten minutes) and at 9:28 p.m. (for nine minutes). In each instance, the NRC Headquarters Operations Center reestablished the link with the site, but the cause of the breakdown was not determined. When personnel in the NRC Headquarters Operations Center attempted several times to communicate either with the site or Region I, the transmission was unintelligible because of signal distortion. A separate FTS line between the Region I Incident Response Center and the NRC Headquarters Operations Center was then established.

The location of the Emergency Notification System's (ENS) phones at the site and in the Region I Incident Response Center also adversely affected communications. The original report from the site was made by the Shift Supervisor using the ENS extension located in his office. However, he could not simul-

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taneously observe parameter indications and direct operator actions from his office. Later, the Emergency Notification System (ENS) was manned in the control room by an individual with a reactor operator's license. The phone was located in the rear of the control room, away from the front panel indications. To respond to NRC questions regarding plant parameters, this individual either had to leave the phone or request that someone get the information for him.

The location of the ENS phone in the Region I Incident Response Center (IRC) did not provide sound isolation sufficient to allow efficient communications in the face of the high ambient noise in the IRC. Personnel in the Region I IRC attempted to discuss aspects of the event with the Senior Resident Inspector while he was in the control room and with individuals present in the NRC Headquarters Operations Center. These attempts were originally made over the ENS, but when signal volume or signal distortion made communications impossible, commercial or separate Federal Telecommunications System lines were used. In addition, it was recognized by individuals in the Regional IRC that the ENS was not appropriate for these discussions since the ENS was heavily involved in communication of plant parameter data required by NRC to track and independently evaluate the event. Commercial lines and separate FTS lines also proved valuable in this area.

An additional problem occurred with the HPN line. During the event, the HPN line in the Senior Resident Inspector's Office would be disrupted if a commercial call was being made from another phone extension in that office.

BEST DOCUMENT AVAILABLE

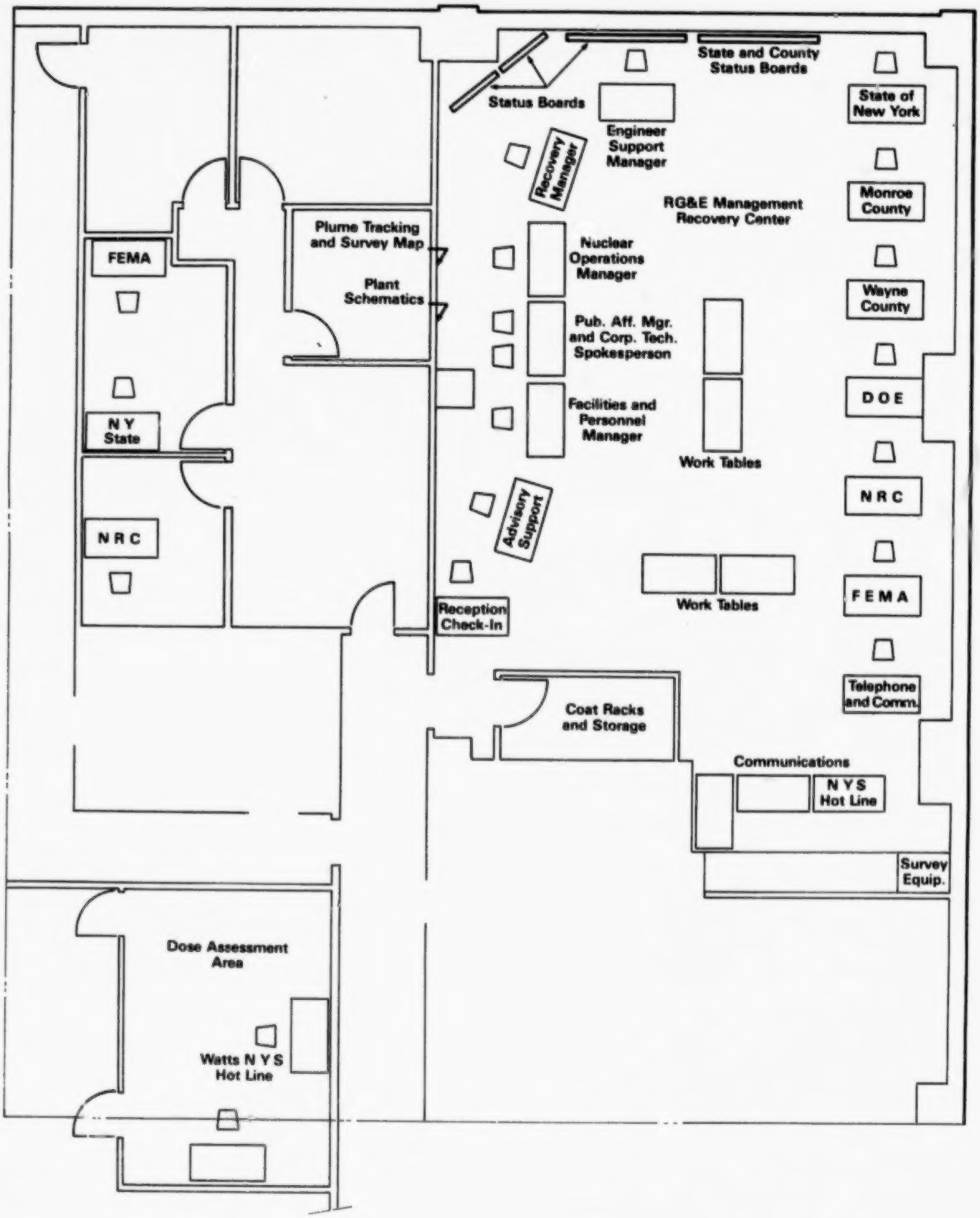
State and County Status Boards
Status Boards
Engineer Support Manager
State of New York
Recovery Manager
RG&E Management Recovery Center
Monroe County
Plume Tracking and Survey Map
FEMA
Nuclear Operations Manager
Wayne County
Plant Schematics
Pub. Aff. Mgr. and Corp. Tech. Spokesperson
DOE
NY State
Facilities and Personnel Manager
Work Tables
NRC
Advisory Support
NRC
FEMA
Work Tables
Reception Check-In
Telephone and Comm.
Coat Racks and Storage
Communications
NYS Hot Line
Survey Equip.
Dose Assessment Area
Watts NYS Hot Line

Figure 6.1 Emergency Operations Facility, Rochester Gas and Electric Corporate Headquarters

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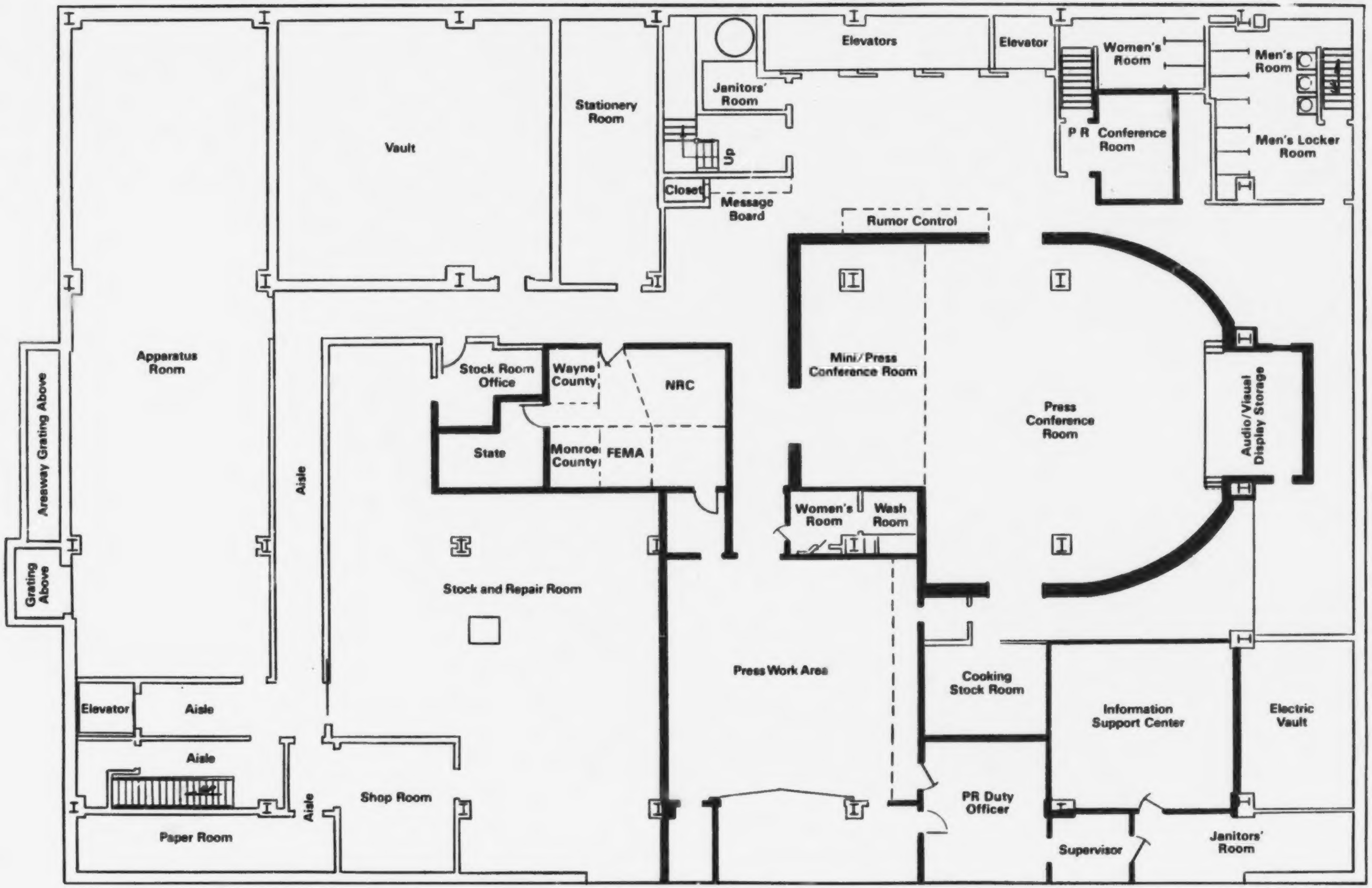

Vault
Stationery Room
Janitors' Room
Up
Closet
Message Board
Elevators
Elevator
Women's Room
Men's Room
P R Conference Room
Men's Locker Room
Rumor Control
Apparatus Room
Areaway Grating Above
Grating Above
Aisle
Stock Room Office
Wayne County
NRC
State
Monroe County
FEMA
Mini/Press Conference Room
Press Conference Room
Audio/Visual Display Storage
Women's Room
Wash Room
Stock and Repair Room
Press Work Area
Cooking Stock Room
Information Support Center
Electric Vault
Elevator
Aisle
Aisle
Shop Room
Aisle
Paper Room
PR Duty Officer
Supervisor
Janitors' Room

Figure 6.2 Public Information Center, Rochester Gas and Electric Corporate Headquarters

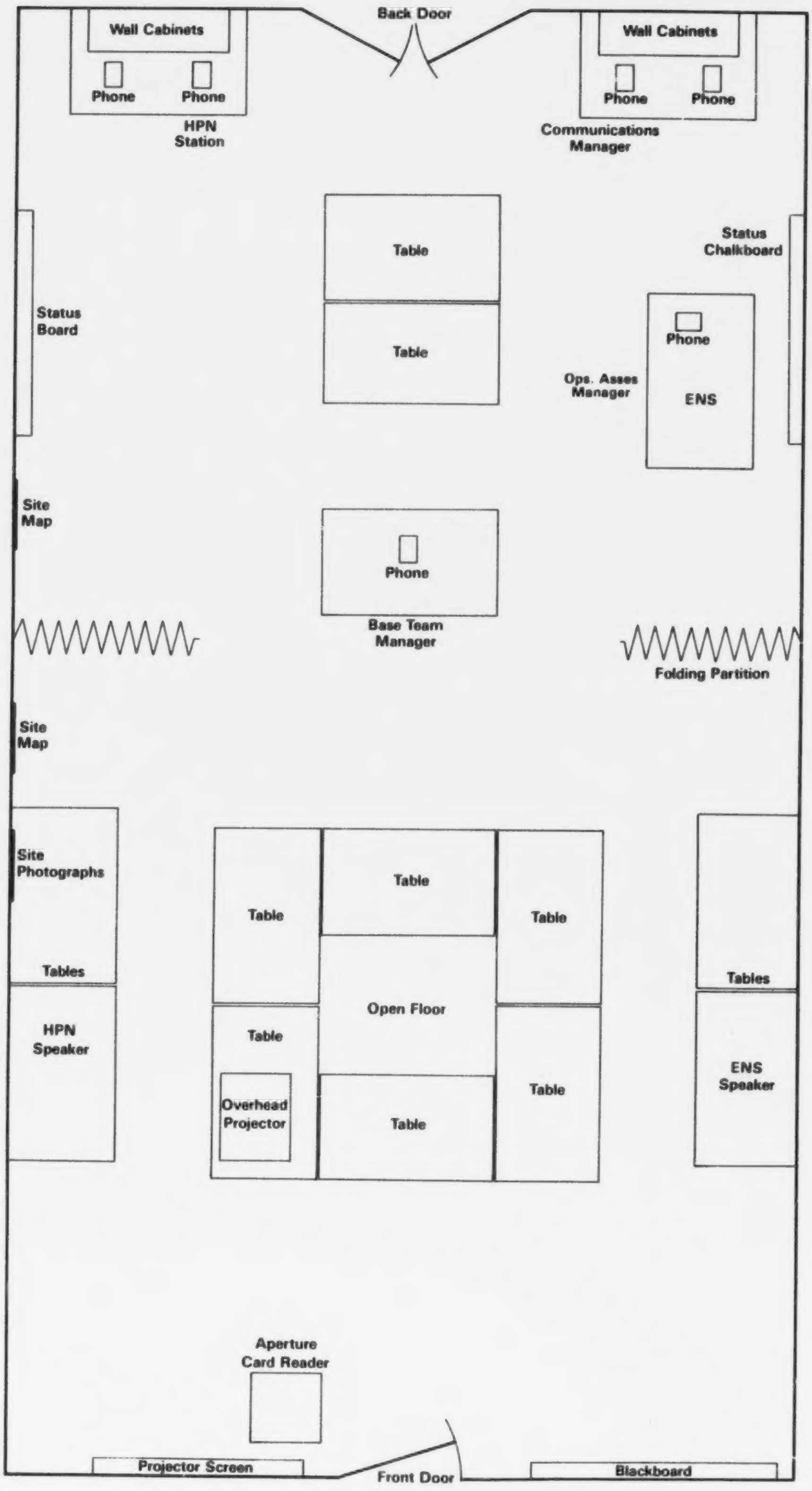
Back Door
Wall Cabinets
Phone
Phone
HPN Station
Wall Cabinets
Phone
Phone
Communications Manager
Table
Table
Status Chalkboard
Status Board
Phone
Ops. Asses Manager
ENS
Site Map
Phone
Base Team Manager
Folding Partition
Site Map
Site Photographs
Tables
Table
Table
Table
Tables
Open Floor
Table
HPN Speaker
ENS Speaker
Table
Overhead Projector
Table
Aperture Card Reader
Projector Screen
Front Door
Blackboard

Figure 6.3 NRC/Region I, Incident Response Center

3RD FLOOR, EW TOWERS

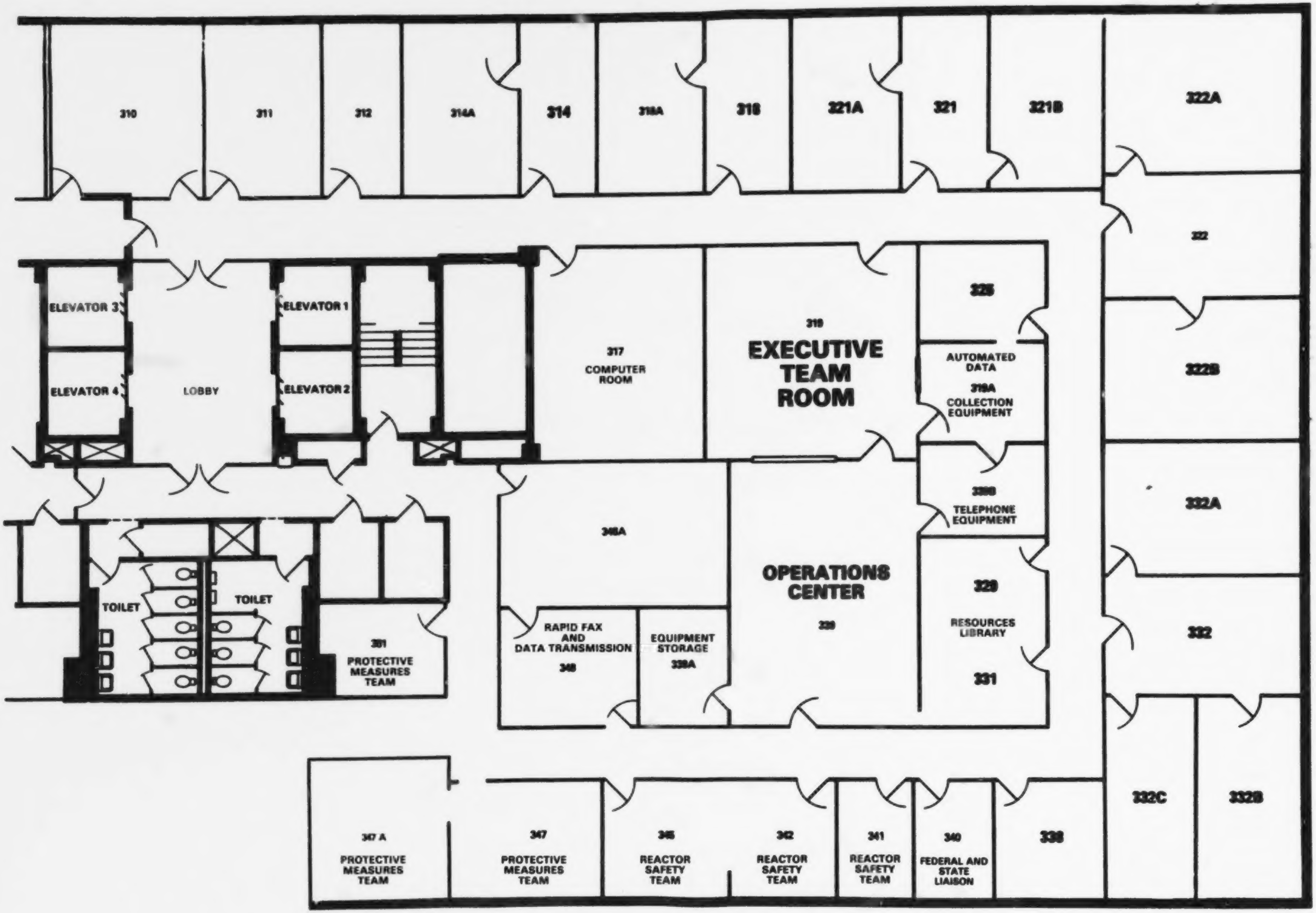
310
311
312
314A
314
318A
318
321A
321
321B
322A
322
322B
332A
332
ELEVATOR 3
ELEVATOR 4
LOBBY
ELEVATOR 1
ELEVATOR 2
317
COMPUTER ROOM
319
EXECUTIVE TEAM ROOM
325
AUTOMATED DATA
319A
COLLECTION EQUIPMENT
339B
TELEPHONE EQUIPMENT
348A
OPERATIONS CENTER
330
329
RESOURCES LIBRARY
331
TOILET
TOILET
351
PROTECTIVE MEASURES TEAM
RAPID FAX AND DATA TRANSMISSION
348
EQUIPMENT STORAGE
339A
347 A
PROTECTIVE MEASURES TEAM
347
PROTECTIVE MEASURES TEAM
345
REACTOR SAFETY TEAM
342
REACTOR SAFETY TEAM
341
REACTOR SAFETY TEAM
340
FEDERAL AND STATE LIAISON
338
332C
332B

Figure 6.4 NRC Headquarters Operations Center

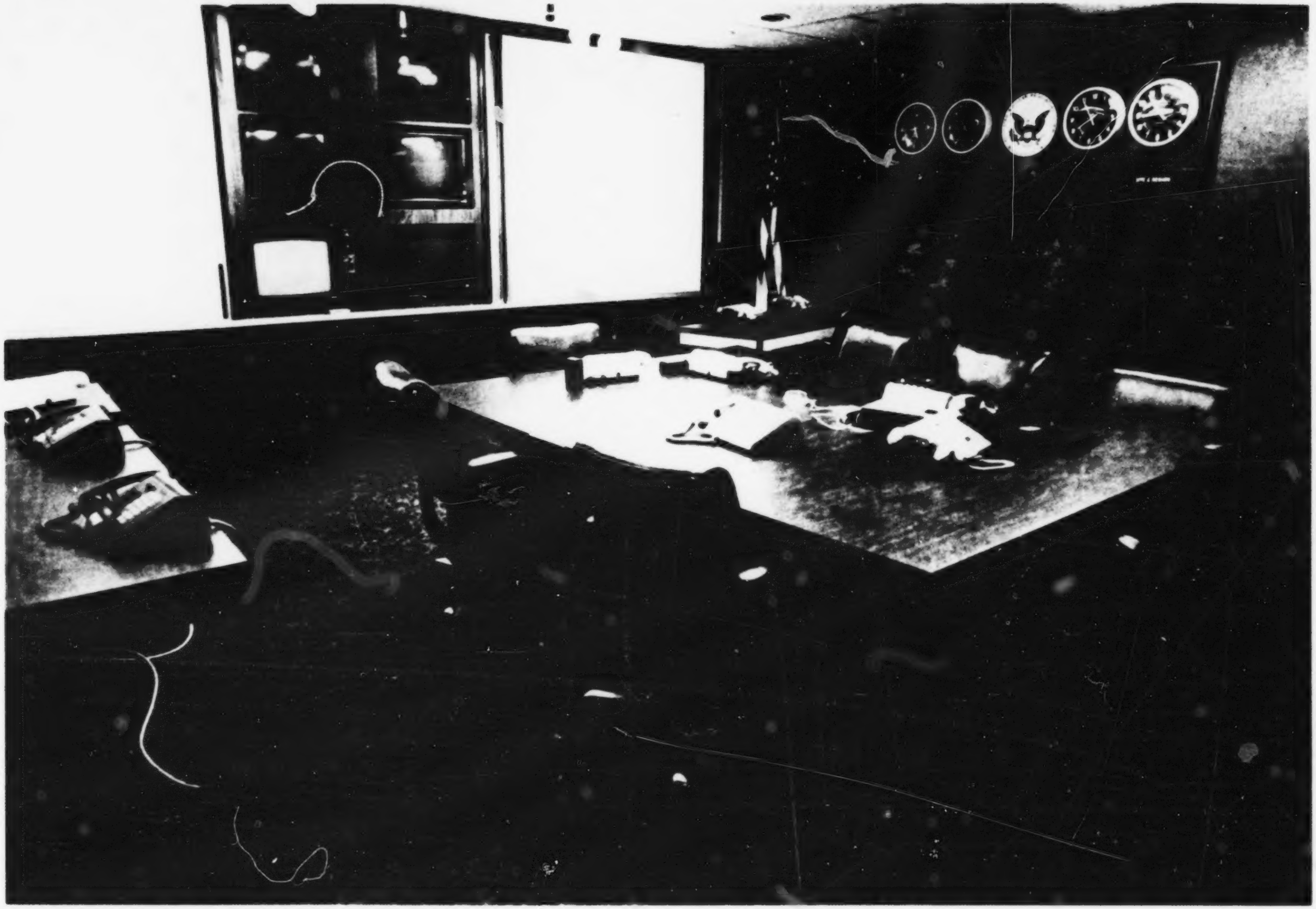

Figure 6.5 Executive Team Room

7 POST-EVENT ACTIVITIES

7.1 Event Termination

At about 7:00 a.m., January 26, the operators placed the residual heat removal system in service. The cooldown continued via the residual heat removal system with the A reactor coolant pump running to permit coolant cleanup and degasification through the letdown system. The licensee declared cold shutdown at 6:53 p.m., January 26, about 33 hours into the event.

At the time of cold shutdown, further degasification was required to meet the licensee's criteria for opening the primary system. After the reactor coolant pump was secured, because of inadequate seal flow, the degasification process stopped. The gas remaining in the reactor coolant was subsequently vented, as discussed below.

7.2 Initial Inspection of the B Steam Generator

7.2.1 B Steam Generator Purge and Drain Down

As a result of the reactor coolant system inleakage into the B steam generator, a noncondensible gas bubble accumulated in the generator steam space. The licensee initially planned to purge this gas volume through the containment ventilation system. The first step was to sample that generator gas space and analyze for hydrogen and total gaseous activity concentration using a specially prepared written procedure. A safety analysis was also prepared to support the sampling and purging operation. For both the safety analysis and the procedure, a total gaseous activity of less than 100 Ci was assumed. The initial gas sample drawn on January 28 indicated a hydrogen concentration of 37% and an activity of about 17 μCi/cc (primarily xenon-133 and xenon-135). The total curie content in the B steam generator determined using the licensee's procedure exceeded the 100-Ci limit established in the purging procedure. The licensee then revised the procedure to require that the steam generator be purged through temporary piping to the pressurizer relief tank for final disposal through the normal waste gas system. The motive force for the purge was provided initially by the gas pressure in the steam generator and then by using a charging pump to raise the reactor coolant system pressure and thus the B steam generator water level. Before the purge, the licensee leak-tested the fittings used in the temporary piping path; during the purge, the licensee analyzed grab samples of the piping area atmosphere for activity and used an explosimeter to monitor hydrogen concentration. No apparent problems occurred during the purging operation.

The Task Force reviewed the licensee's calculations for hydrogen and total gaseous activity concentrations in the B steam generator. The Task Force determined that the licensee's results were in error because the dilution factors used by the licensee in calculating the results were incorrect. The plant chemist used dilution factors that apply to the analysis of normal, pressurized reactor coolant system liquid samples. The sample drawn from the B steam generator was gas, with essentially no liquid, so the licensee's dilution factors did not apply. Independent calculations performed by the Task Force indicated that the minimum hydrogen concentration in the B steam generator was 56%, and the minimum activity was about 7.3 µCi/cc. The NRC Task Force could not calculate the exact hydrogen concentration and total gaseous activity because the Task Force could not determine the gas pressure that existed in the sample bomb at the time the steam generator sample was collected. It should be noted that, with a gaseous activity concentration of 7.3 µCi/cc, the total curie content in the steam generator would have also been greater than 100 Ci, and purging the B steam generator to the waste gas system would still have been warranted.

The licensee completed the purging operation on January 31. No accurate estimate of the total gas volume and the total activity purged was available.

The licensee drained the B steam generator, together with the reactor coolant system, to the CVCS holdup tanks in preparation for inspection of the steam generator. The B steam generator drained to a level just below the rupture; the reactor coolant system drained sufficiently to clear the steam generator channel head of water. During and after the draindown, a nitrogen blanket was maintained on the reactor coolant system, the pressurizer, and the B steam generator. After completing the draindown procedure on February 1, the licensee determined that the elevation of the rupture was below the first tube support plate.

7.2.2 Initial Rupture Location

To locate the leaking tube and to allow steam generator tube inspection, the licensee removed the primary side manways on the B steam generator channel head. Initially, on February 3, the leaking tube was located by adding about 20 gal of water to the secondary side of the steam generator using an auxiliary feedwater pump. Water was noted exiting the tube located at Row 42, Column 55 (R42C55). The licensee then performed a manual eddy-current test on this tube. The eddy-current test results showed an axial through-wall defect, about 5 in. long, starting about 2 to 4 in. above the tubesheet. A fiber-optics examination indicated the defect to be a fish-mouth-shaped tube rupture.

7.2.3 Steam Generator Refill and Subsequent Removal of Boric Acid From the Reactor Coolant System

The licensee decided to refill the B steam generator to remove the boric acid deposited on its shell side as a result of the tube rupture. As directed by a written procedure prepared for this task, a temporary plug was installed in the hot-leg side of the ruptured tube; however, the cold-leg side remained unplugged because the procedure did not address this action. Auxiliary feedwater was used to fill the generator. Late on February 3, as the steam generator water level increased, the control room operator noted a change in indicated reactor coolant system level. Water from the B steam generator was flowing through the rupture, up over the U-bend, and out the unplugged cold leg of the ruptured tube by a siphoning effect. The siphoning continued until about 2:30 a.m., February 4, when it was broken by a technician inserting an air hose into the cold-leg side of the tube. About 2,300 gal of water was added to the reactor coolant system inventory, resulting in a reduction in boron concentration from about 1,900 ppm to about 1,685 ppm.

The steam generator was placed in wet layup on February 5, and the B steam generator main steam line was drained to the CVCS holdup tanks. The B steam generator was subsequently drained for secondary-side TV-optics inspection on February 8.

7.3 Steam Generator Tube Degradation

7.3.1 Background

Pressurized water reactor steam generators supplied by the various nuclear steam supply system vendors have, over a number of years, experienced a variety of tube-degradation problems. The problems have included degradation caused by tube corrosion, vibration, mechanical wear or impact, and the phenomenon known as "denting." These mechanisms have been discussed in detail in other NRC documents and in the industry's literature. This report specifically addresses the peripheral tube degradation problems identified in the Ginna B steam generator and the licensee's efforts to determine the causes for the tube rupture.

7.3.2 Steam Generator Design, Fabrication, and Modification

The Ginna plant is a two-loop pressurized water reactor system with one Westinghouse Model 44 (44,000 ft^2) vertical U-tube steam generator per reactor coolant loop. The steam generators were fabricated by the Westinghouse Heat Transfer Division and are similar to those at H. B. Robinson, Point Beach 1 and 2, Indian Point 2, and Turkey Point 3 and 4.

Figure 7.1 shows a cutaway view of this type of steam generator. The primary channel head, the tubesheet, and the 3,260 U-tubes form the reactor coolant pressure boundary within the steam generator. Feedwater enters the secondary side of the steam generator through an inlet nozzle and internal feed ring. The preheated water flows down the annulus formed by the tube wrapper and the shell (the downcomer annulus), and then flows between the end of the wrapper and the tubesheet into the tube bundle. The U-tubes provide the surface area needed to transfer heat from the primary system to the secondary system.

Moisture separators and dryers are located above the tube bundle. These components function to improve steam quality by removing entrained moisture from the steam leaving the tube bundle. The moisture removed from the steam is recycled through the downcomer annulus for mixture with the incoming feedwater.

Both steam generators were shipped to the site as lower shell (including transition ring and tube bundle) and upper shell (including moisture-separation equipment). The wrapper transition piece and shell closure welds were completed by Westinghouse at the site.

Components significant to the discussion that follows in this report are the tubes and tube bundle, the tubesheet, the tube support plates, the downcomer flow-resistance plate, the tube bundle wrapper, the stub barrel, and the shell.

The tubes of each steam generator are 7/8 in. O.D. by 0.050-in. wall, U-bend tubes made of a nickel-chromium-iron alloy. The tubes were rolled and welded to the tubesheet, but were not expanded in the tubesheet beyond the length expanded in shop fabrication. During fabrication, Westinghouse plugged one B steam generator tube that was mechanically damaged.

The tubesheet is a 22-in.-thick, low-alloy steel forging that is clad with a nickel-chromium-iron alloy and has drilled holes to accept the U-tubes. The tubesheet is welded to the stub barrel section of the shell.

Carbon steel drilled tube support plates are spaced throughout the axial length of the vertical sections of the tube bundle and are numbered sequentially, starting from the first support above the tubesheet. These plates provide lateral support to the tube bundle. The tube support plates are attached to the wrapper by means of wedges, which are welded to the wrapper and to each support plate. Around the periphery of each support plate are 12 equally spaced wedge location areas, six on the hot-leg side and six on the cold-leg side. Only half these areas on each individual plate are used to support the plate. For the first and odd-numbered tube support plates, wedge areas 2, 4, 6, 8, 10, and 12 are the locations where the tube support plate is affixed to the wrapper. Wedge areas 1, 3, 5, 7, 9, and 11 are used for the even-numbered tube support plates.

The shell is made of low-alloy steel plate. It forms the outer boundary of the downcomer annulus and provides support for the upper internals of the generator.

The flow-resistance plates were originally designed to meter flow to the tube bundle. To improve corrosion performance in the sludge area, Westinghouse recommended steam generator modifications which included removal of these plates. The Westinghouse recommended modifications are described in the licensee's "Design Verification Report for Orifice Ring Replacement, Feedwater Ring Modification, Downcomer Resistance Plate Removal, Tube Lane Blocking, and Redirection of Blowdown Suction," document EDR 1062, dated April 21, 1975. The removal of the plates was accomplished in 1975 by oxyacetylene cutting in accordance with the licensee's procedure SM-75-24.3, Rev. 0. This procedure did not require the reconstruction of the parts removed from the steam generators.

Steam generator tubes that have leaked or have shown sufficient indications of degradation during eddy-current testing have been either plugged or sleeved. Tube plugging has been performed on these and other Westinghouse steam generators by a variety of methods. Initial tube plugging was performed using a manual multi-layer gas tungsten arc welded solid plug as described in the Westinghouse Steam Generator Equipment Manual. Explosive welded thimble plugs have also been employed. Most recently, Ginna has been utilizing a proprietary Westinghouse mechanical plug that is expanded after insertion into the tube hole. The Westinghouse mechanical plug and plugging procedure are similar to those utilized at San Onofre. The plugs are designed and installed by a procedure that permits future removal for the purpose of sleeving repair and reactivation of the tube surface, where applicable. The sleeving procedure utilized by Ginna is a proprietary Babcock & Wilcox procedure. A total of 21 tubes have been sleeved on the hot leg side in the B steam generator. Of these, 5 were installed in November 1980 and 16 in April 1981. One of the five tubes sleeved in November 1980 was a tube without eddy-current indications that was sleeved for base-line evaluation purposes.

7.3.3 Steam Generator Operating Environment

The steam generators started commercial operation in 1970 on coordinated phosphate chemistry control and continued on this regime until December 1974. Since December 1974, the steam generators have operated on all-volatile treatment. Full-flow polishing demineralizers were installed and have been in service since January 1978. The full-flow condensate polishing mixed-resin bed demineralizers have the capability to remove 85% of the Fe_3O_4 and 93% of the copper from the feedwater train. An example of the amount of these materials removed is 500 to 600 lb/yr of Fe_3O_4 and 70 to 75 lb/yr of copper.

Hydrazine (N_2H_4) and ammonium hydroxide (NH_4OH) are injected into the feedwater at the effluent point of the condensate polishers (before the low-pressure feedwater heaters).

Typical full-power secondary-side water chemistry, as measured at the steam generator blowdown, is as follows:

8.5 to 9.0 pH
5 to 15 ppb Na
3 to 10 ppb Cl
<0.3 micromho cation conductivity
0.08 to 0.15 ppm NH_3
15 to 75 ppb N_2H_4 (excess)

The oxygen is <10 ppb at the condensate pump discharge and 2 to 3 ppb at the feedwater inlet to the steam generator (full power). The condenser circulating (lake) water has 23 to 29 ppm chlorides.

Copper is introduced into the condensate and feedwater system by dissolution of heat exchanger materials. The main condenser has Admiralty Metal (brass) tubes with stainless steel peripheral and air offtake tubes. The feedwater heater tubes are: No. 1, No. 2, and No. 3, which are Admiralty Metal; No. 4, which is

90/10 copper-nickel, and No. 5 (HP), which is 80/20 copper-nickel. The condenser and feedwater heaters were, at the time of the rupture, original construction equipment.

Steam generator sludge, which consists mainly of oxides of iron and copper and elemental copper, is partially removed by blowdown. A significant amount of sludge is also removed during outages by sludge lancing. Sludge lancing is conducted at Ginna in accordance with Maintenance Procedure M-43.23, which references Westinghouse Steam Generator Tubesheet Cleaning Procedure MRS2.2.2, GEN-9. High-pressure demineralized water is pumped through a specially designed water lance. The water lance is inserted through one secondary-side hand hole and the nozzle of the lance is directed down individual tube columns to inject the high-pressure water. Low-pressure water is also injected through a secondary-side hand hole and directed around the periphery of the steam generator. The action of both streams of water provides a constant high-volume washing of the tubesheet to levitate and permit removal of deposits dislodged by the high-pressure flow. The water is removed from the generator, filtered, and returned to a lancing-system holding tank.

Procedures used to remove contaminant chemicals in the tube-to-tube sheet crevice area employ a cyclic treatment, including soaking, heatup, pressurization and depressurization of the secondary side of the steam generator to produce a boilout and reduction in contaminants. Originally demineralized water was used for this operation. Currently, a solution of boric acid in water is being used to aid in neutralizing the basic chemicals causing intergranular attack in the crevice area.

Ginna does not employ shell-side boric acid soaks or boric acid additions to the feedwater to remove metal chlorides from the tube support plate crevices.

7.3.4 Inservice Inspection Eddy-Current Examination

Appendix B of the Ginna Station Quality Assurance Manual presents the licensee's inservice inspection program. This document commits to the requirements of Title 10, Section 50.55a of the Code of Federal Regulations and follows the guidance of Section XI of the ASME Code. The selection of steam generator tubes for examination and the extent of these examinations are as described in NRC Regulatory Guide 1.83, Revision 1, dated July 1975. The primary-to-secondary steam generator leakage limits are established in the plant technical specifications. Appendix B of the Ginna inservice inspection program establishes the bases for interpretation of the nondestructive examination results and specifies the tube integrity requirements that are prerequisite for plant operation.

Single-frequency differential coil techniques were employed for eddy-current examination until April 1978. In April 1978, multifrequency differential coil techniques using the French equipment were instituted. Starting in April 1980, Zetec multifrequency differential and absolute coil techniques were used.

Eddy-current examination of steam generator tubes is currently conducted in accordance with the licensee's Procedure NDE-500-4, Revision 4. This procedure utilizes standard Zetec bobbin-type coil probes, a Zetec Vector Phase Analyzer with an integral series 5103N two-channel storage-display oscilloscope, a Hewlitt Packard/Zetec HP3968AZ magnetic-tape recorder, and two Gould 220 brush strip-chart recorders.

The eddy-current examination is conducted by the licensee's Level II eddy-current technicians, and the results are evaluated by a Zetec Level III eddy-current consultant. The disposition of the evaluated data is made by Level III-qualified licensee engineering personnel.

7.3.5 Hot-Leg Peripheral Tube Problems

The tubes in the vicinity of the first tube-support-plate wedge locations, on the hot leg of B steam generator, have shown indications of tube distress since 1976. The problem has been limited to the hot leg of the B steam generator, and a representative of the Westinghouse Electric Corporation has indicated that there have been no similar peripheral tube problems reported in other Model 44 or Model 51 steam generators (nor in the Ginna A generator).

Figure 7.2 shows the location of tubes that had been plugged or sleeved in the B steam generator prior to the time of the tube rupture. There are two general regions of the tube bundle where tube degradation has been identified; i.e., the sludge area which experienced corrosion problems, and the peripheral areas in the vicinity of the welded wedges which, in general, have experienced problems having characteristics not normally ascribed to corrosion. The licensee's reason for plugging the peripheral tubes included tube leakage, unacceptable eddy-current indications, or proximity to other degraded tubes. A historical summary of tube plugging based on eddy-current examination results is given in Table 7.1.

The January 1976 routine inservice inspection eddy-current examination reportedly indicated outer-surface wastage within the tubesheet for tubes R40C68 and R39C69. These tubes were plugged.

On April 24, 1976, during normal operation, there was indication of a small (0.06-gpm) leak in the B steam generator. The leak was identified as being on the hot leg of R12C91 in the No. 6 wedge area (6W) above the tubesheet. Single-frequency (differential coil) 400-kHz eddy-current examination was conducted and pluggable tubes were identified in the No. 6 and No. 2 wedge (2W) areas.

On July 5, 1977, during normal operations, there was indication of a small (0.006-gpm) leak in the B steam generator. The leak was identified as being on the hot leg of R45C54 in the No. 4 wedge (4W) area above the tubesheet. Single-frequency (differential coil) 400-kHz eddy-current examination was

Table 7.1 NRC task force summary listing of plugged peripheral tubes

Date/Event	Tube	Location	Licensee's Reason for Plugging (see notes)
1/76/Outage	R39C69	4W*	(b)(c)(i)
	R40C68	4W*	(a)(i)
5/76/Leak	R8C92	6W	(f)
	R9C91	6W	(a) (d) (e)
	R10C91	6W	(d) (e)
	R11C91	6W	(c)
	R12C91	6W	Leaker (a) (c)
	R13C90	6W	(a) (d) (e)
	R14C90	6W	(a) (d) (e)
	R15C90	6W	(a) (d) (e)
	R15C89	6W	(a) (c)
	R16C89	6W	(a) (e)
	R17C89	6W	(a) (e)
	R30C15	2W	(b-47%) (e)
	R31C15	2W	(b-43%) (e)
	R33C15	2W	(a) (c)
7/77/Leak	R45C54	4W	Leaker (a) (c)
	R44C55	4W	(a) (c)
	R44C56	4W	(a) (c)
	R44C57	4W	(a) (c)
	R44C58	4W	(a) (c)
	R12C2	4W	(g)
1/78/Leak	R44C54	4W	Leaker (a) (c)
	R45C53	4W	(a-50%) (c)
4/78/Outage	R45C50	4W*	(c) (g)
	R45C51	4W*	(c) (g)
	R45C52	4W*	(a) Tube pulled
	R44C52	4W*	(c) (g)
	R44C53	4W*	(c) (g)
	R43C58	4W*	(a) (c) (d)
	R43C59	4W*	(a) (c) (d)
	R43C60	4W*	(a) (c) (d)
	R43C61	4W*	(a) (c) (g)
	R41C66	4W*	(c) (c)
	R40C67	4W*	(a) (c) (d)
	R39C68	4W*	(c) (g)
	R39C70	4W*	(a) (c)
	R38C71	4W*	(a) (c)
	R38C72	4W*	(a) (c)
2/79/Outage	R28C12	2W	(b-40%) No. 1 TSP
	R43C55	4W	(b-40%) (c)
	R43C56	4W	(b-68%) (c)
	R35C75	4W*	(b-50%) No. 2 TSP
12/79/Leakage	R43C54	4W	Leaker (a) (c)
	R43C57	4W	(a) (e)
4/80/Outage	R45C48	4W (11)	(2), 46%
	R45C49	4W (11)	(2), 23%
	R32C16	2W	(2) (4)
	31 tubes	Sludge, crevice	
4/81/Outage	R43C53	4W	(2), 75 to 80%
2/82/Leakage	R42C55	4W	Tube rupture

Notes:
(a) Inner surface metal loss
(b) Outer surface metal loss
(c) Indication above tubesheet
(d) Dent at first tube support plant
(e) Indication 2 to 4 in. above tubesheet
(f) Precautionary plug
(g) Uninterpretable signal on outer or inner surface
(h) 24 in. above tubesheet
(i) Within tubesheet

conducted, and pluggable tubes were identified in the No. 4 wedge area. Tubes R45C54, R45C2, and R45C53 showed eddy-current indications below the plugging criteria. The licensee reported that the tube degradation was postulated to be caused by inner-surface stress-corrosion cracking as a result of stress-induced by tube deformation. The inner-surface corrodant was not known.

On January 25, 1978, during normal operations, there was indication of a small (0.00725-gpm) leak in the B steam generator. The leak was identified as being on the hot leg of R44C54 above the tubesheet. Single-frequency (differential coil) 400-kHz eddy-current examination was conducted and pluggable tubes were identified in the No. 4 wedge area immediately adjacent to previously leaking tube R45C54. The previous eddy-current test (July 5, 1977) of the leaking tube were interpreted by the licensee as a small inner surface loss of metal indication below the plugging criteria of >40%. The inner surface indication previously reported for tube R45C53 had increased to 50%. The licensee attributed the failure to inner-surface stress-corrosion cracking.

During an outage in April 1978, an inservice inspection eddy-current examination showed tubes in the No. 4 wedge area with indications of damage. Tube R45C52 was removed for metallurgical examination by Westinghouse, and the results of the investigation were subsequently reported by EPRI in report NP-1412, Project 1166-2 Final Report, May 1980. The tube was removed because of apparent tube bulge deformation and possible inner-surface stress-corrosion cracking. Dimensional abnormalities were confirmed; however, there was no evidence of inner-surface stress-corrosion cracking. Of those tubes tested, only R45C52 had apparent "bulging." Of the plugged tubes, three tubes were adjacent to the two tubes (R40C68 and R39C69) which were previously plugged (January 1976) based on outer-surface crevice wastage (within the tubesheet).

During an outage in February 1979, one tube in the No. 2 wedge area, two tubes in the No. 4 wedge area, one tube adjacent to the No. 4 wedge area, and two tubes in the sludge area showed indications of degradation. Tubes R28C12 and R35C75 were plugged because of reported apparent outer surface steam erosion. Tubes R17C39 and R18C42 reportedly showed crevice attack. The eddy-current testing employed multi-frequency (200 and 400 kHz) differential and 100- and

[redacted]

210-kHz absolute coil techniques. Disposition of eddy-current data from the absolute coil testing was not made at this time. Tubes R43C55 and R43C56 reportedly showed outer-surface metal loss. These tubes were adjacent to previously plugged tubes, and R43C55 was also adjacent to a previous "leaker."

On December 1, 1979 during normal operations, there was an indication of a small (0.007-gpm) leak in the B steam generator. Two tubes were found to be leaking. One of the tubes (R15C37) was in the sludge-crevice area and indicated a defect location four inches below the top of the tubesheet. Eddy-current testing of the other leaking tube (R43C54) and of R43C57 reportedly indicated large-volume outer-surface defects. Tube R43C57 indicated an 80% outer-surface metal-loss signal. Tube R43C57 was immediately adjacent to three previously plugged tubes, and tube R43C54 was immediately adjacent to a previous leaker. The licensee reported the probable cause of the tube defects for R43C54 and R43C57 to be thermal/hydraulic and mechanical loading of the tubes in this area. The licensee reported that the crevice-area tube problem was attributable to chemical hideout outer-surface stress-corrosion cracking.

Eddy-current inservice inspection in April 1980 using Zetec multifrequency differential and absolute coil techniques reportedly indicated two tubes (R45C48 and R45C49) in the No. 4 wedge area and one tube in the No. 2 wedge area with outer-surface metal loss and 31 tubes with outer-surface crevice problems. All 34 tubes were plugged. R45C48 and R45C49 are adjacent to a row of five previously plugged peripheral tubes and the indications on these two tubes are 24 in. above the tubesheet. The licensee reported that the defects identified most probably had been in the tubes for several years and had now developed into pluggable indications. The licensee assessed the peripheral tube data as indicating small-volume loss signals without a great amount of depth, each one less than 50%.

An eddy-current examination conducted in November 1980 showed no additional pluggable tubes when the results were compared with the standard inservice inspection plugging criteria. However, eddy-current inservice inspection in April 1981 reportedly indicated a 75 to 80% outer-surface large-volume metal loss with an axial length of several inches in tube R43C53. This tube progressed from no indications from a test in November 1980 to the large-volume axial-length defect in April 1981. The location of the tube was two rows removed from the periphery but immediately adjacent to a previously plugged leaker (R43C54), another previously plugged tube (R44C53), and next to R44C53 which had been precautionarily plugged in April 1978. There were no other reported significant eddy-current indications in the wedge area at this time.

Following the tube rupture event, the ruptured tube was identified as R42C55 by a leakage test described in Section 7.2.2 of this report. The tube that failed was immediately adjacent to two tubes that were previously plugged (R43C55 and R43C56) and tube R43C54 which was a previous leaker in December 1979. The licensee's review of the eddy-current tapes from the April 1981 examination indicated that the ruptured tube exhibited no differential coil signal but did indicate a 4-in.-long absolute coil signal estimated with the calibration standards utilized to represent a 20% outer-surface metal-loss indication. Following the tube rupture event, both steam generators were examined by eddy-current methods. The examination included 100% of the hot legs of both steam generators, 100% of the peripheral tubes on the cold legs, and a total of approximately 30% of the remaining cold-leg tubes. The eddy-current examination resulted in the identification of 13 B steam generator tubes exhibiting an increase in outer-surface crevice-related corrosion problems that required tube plugging. In addition to these 13 tubes, the ruptured tube was plugged and three tubes adjacent to the ruptured tube were plugged for precautionary reasons. All 13 tubes with crevice-related corrosion had previously indicated outer-surface corrosion below the plugging limit. Tubes R45C46 and R45C47, which had indications 24 in. above the tubesheet, were plugged. Tube R6C45 was plugged for precautionary reasons. No new tubes were identified as exhibiting crevice-related corrosion problems. With the exception of the ruptured tube, there were no eddy-current indications of tube outer- or inner-surface problems above the tubesheet on either steam generator. Figure 7.3 shows the status of the plugged or sleeved tubes as of February 9, 1982.

7.3.6 Fiber-Optics Examination of the Failed Tube

A fiber-optics examination of the inner surface of the ruptured tube was conducted in accordance with the licensee's procedure normally utilized for the examination of the steam generator secondary side. The inner surface of tube R42C55 was examined remotely by a 9-ft long, forward-looking, fiber-optics scope with an Olympus 6- and 10-mm lens. The information gathered was recorded on video tape. The lens configuration, capable of operating in the nominally 0.775-in.-ID tube produced a distorted, foreshortened image of the tube rupture, as shown in Figure 7.4. The defect was identified as an axial tube rupture approximately 5 in. long and 0.75 in. wide at its center. The axial length of the rupture agreed closely with that obtained from earlier eddy-current tests on R42C55. The failure exhibited considerable ductility. The rupture was located close to the shell side of the tubesheet, with the bottom of the rupture at a distance estimated to be 2 to 4 in. above the tubesheet. The fish-mouth appearance of the tube rupture was similar to that described in NUREG-0651 for the Prairie Island fretting-induced tube failure, and it was visually similar to the elliptical, zero wrap angle wastage ruptures shown in NUREG/CR-0718. Dimensional constraints and the limitations of the optics prohibited a visual examination of the rupture in such a way that tube wall reduction at the fracture face could be estimated. The radial orientation of the flaw could not be established accurately by this visual examination.

7.3.7 Strain-Gauge-Profilometer Examination of the Failed Tube

The Babcock and Wilcox (B&W) Alliance Research Center (B&W/ARC) eight-finger radial-profilometer strain-gauge probe was used to determine the azimuthal location of the rupture in a procedure similar to the standard inservice inspection procedure for radial profilometry examination for steam generator tubing (ISI-421, Rev. 3). This examination indicated that the rupture was either pointing at tube R43C56 or tube R41C54 as shown in Figure 7.2. Subsequent visual observations made through a 3-in.-diam hole machined through the steam generator stub section indicated that the rupture pointed outward, along column 55.

7.3.8 TV-Optics Examination of Tube Bundle

A remotely controlled TV-optics method was utilized to visually examine the area between the tube bundle and the wrapper from above the tubesheet to the first tube support plate and to view down the tube columns of the hot leg of the B steam generator from the tube lane. A standard Westinghouse Electric Corporation underwater reactor vessel camera, Model ETV 1250, was used for this examination. Access for the camera was provided by the secondary-side hand-hole nozzles. The peripheral area was illuminated with a lighting system consisting of a series of 10-watt, clear, Christmas-tree-type light bulbs at approximately 3-inch spacing inside a 2½-in.-diam, air-cooled, Tygon plastic tube. The Tygon tube was installed to encircle the tube bundle and was laid on the tubesheet. The TV camera was mounted on a stainless steel sled, which straddled the Tygon tubing. The column location of the area being examined was determined from a temporary marker cable which identified tube columns by tab numbers. The tube column marker tabs were attached to the cable by using the licensee's onsite steam generator tubesheet mockup to accurately locate the markers. The marker cable was wrapped around the bundle and located approximately 10 in. above the tubesheet.

The TV camera was remotely operated and required constant refocusing because of the circular path being examined. The data obtained were videotaped. Details of the visual examination are summarized in Table 7.2. The TV-optics examination indicated severe damage to previously plugged peripheral tubes and identified foreign objects and loose pieces of tubes in the peripheral area. The damage observed included tubes with large holes, tubes with longitudinal and circumferential fractures, tubes completely severed at the top of the tubesheet, tubes with dents, and tubes plastically deformed sufficiently to be classified as collapsed. Portions of the videotape recordings have been computer-enhanced by the Jet Propulsion Laboratory and are shown as Figures 7.5 to 7.9.

With the exception of the No. 4 wedge area on the hot-leg side of the B steam generator, it was possible to view down all columns and to view the peripheral annular space between the tube bundle and stub barrel inner surface on the hot-

and cold-leg sides of both steam generators. Debris in the No. 4 wedge area prevented complete passage of the TV camera, but the area was partially observable from both sides.

Table 7.2 Results of TV Optics Examination in the B Steam Generator as of February 16, 1982

Tube (Row Column)	Licensee's Recorded Indication on Visual Examination
HOT LEG:	
R8C92	Collapsed plus a hole
R9C91	Ripples on outer surface
R10C91	Outer surface wiped and scraped
R11C91	Collapsed plus a hole
R12C91	Collapsed plus a hole
R13C90	Outer surface damage
R14C90	Collapsed plus outer surface depression
R15C90	Collapsed plus a hole
R16C89	Outer surface damage
R17C89	Outer surface damage
Near R30C81	Piece of tube on tubesheet
R38C72	Outer surface damage
R38C71	Outer surface damage
R39C70	Outer surface damage
R39C69	Outer surface damage
R39C68	Outer surface damage
R39C65	Dings*
R41C64	Dings*
R42C64	Dings*
R42C63	Dings*
R42C62	Dings*
R43C61	Severed at tubesheet
R43C60	Outer surface scraped
R44C58	Collapsed
R44C57	Collapsed (possibly missing)
R44C56	Collapsed
R44C55	Collapsed
R44C54	Collapsed
R44C53	Collapsed
R45C51	Ripples on outer surface
Near R43C34	Piece of wire
Near R32C15	Piece of tube wedged between R32C15 and stay bar
COLD LEG:	
Near R33C67	Piece of tube on tubesheet
Near R40C25	Small square object on tubesheet, about 3/4 in. x 3/4 in., covered by sludge dust
R6C1	Outer surface scraped
R5C1	Outer surface scraped

*Dings are localized indentations on the surface of the tube.

As previously mentioned, the TV-optics examination identified the existence of foreign objects on the tubesheet. The most significant object found in the B steam generator was a plate that had the dimensional characteristics of a portion of the downcomer flow-resistance plate which had been cut out and removed in 1975. This foreign object is approximately pieshaped, as shown in Figure 7.10. The size is roughly 4.13 x 6.5 x 0.5 in. thick. The material is magnetic and has the appearance of carbon steel plate. The edges appear to be oxyfuel cut. On one side there is a portion of a hole of the same diameter as the orifice holes in the downcomer resistance plate. The plate contains a raised section which may be a portion of the fillet welded stiffener that was attached to the flow-resistance plate. Visual examination of the surface of the foreign object shows two parallel grooves in the plate whose curvature and center-to-center spacing is similar to the tube bundle spacing. Other objects of smaller dimensions, but appearing to be of similar material were found in other locations on the tubesheet, including one object found on the cold-leg side. In addition, parts of fractured tubes and tube fragments were found.

The locations of some of the foreign objects in the B steam generator are indicated in Table 7.2, and are described as follows:

1. Two long sections of tubing detached from the bundle. Their length currently has not been determined, but it was estimated to be approximately 30 in. The two tubes were adjacent to each other.
2. A 0.5 x 0.75 x 3.5-in. rectangular piece (probably carbon steel).
3. A 0.06 x 0.75 x 3-in. strip (probably carbon steel).
4. A piece of wire, 0.04 x 4 in. long (nonmagnetic).
5. Three pieces of tube fragments.

In addition, the following objects were identified in the A steam generator during its TV-optics examination:

1. A 0.4 x 0.75 x 0.75-in. object with flame-cut edges (probably carbon steel).
2. A 0.125-in. rod which appeared to be a welding electrode stub.
3. A piece of small-diameter wire.

A pictures of the three foreign objects found in the A steam generator is shown in Figure 7.11.

7.3.9 Tube Rupture Mechanism

The licensee has not reached a conclusion as to the exact failure mechanism for the ruptured tube or the sequence of events that led to the tube rupture. The licensee and Westinghouse Electric Corporation are continuing to investigate flow-induced mechanical tube loading, mechanical wear, impact damage and combinations of these phenomena.

The licensee removed the ruptured tube from the unit for metallurgical evaluation and reported the results of a cursory visual examination to the Task Force. The ruptured tube (R42C55) showed what appeared to be a fresh, axial band of fretting wear with transverse striations. There were also indications of previously oxidized wear markings. The total length of the rupture was 4.1 in., with the wide mouth of the rupture measuring 0.7 in. The tube locally ballooned to a diameter of 1.15 in. at the rupture location. The wall thickness at the rupture point was found to be reduced to approximately 5% of the original wall thickness with the rupture stopping at a point where the wall thickness was estimated to be approximately 50% of the original wall thickness. The rupture exhibited considerable ductility. The appearance of the failure was similar to that shown in Figure 40 of NUREG/CR-0718, Steam Generator Tube Integrity Program - Phase I Report, which shows burst failure mode of elliptical wastage (85 to 90% deep).

The licensee removed 9-in.-long segments of the ruptured tube and five other tubes in the No. 4 wedge area for metallurgical examination at the Westinghouse Research and Development Center hot cell laboratory. The tubes removed for examination by Westinhouse were tubes R43C56, R44C55, R43C55, R42C55 (ruptured tube), R44C54 and R43C54, and a segment of an unidentified loose tube. Visual examination by a member of the Task Force indicated the following:

> All tubes exhibited axial outer surface markings similar in appearance to classical fretting wear with transverse scoring caused by surface asperities.

- Tubes R44C55, R43C55, and R42C55 exhibited multifaceted markings (as many as six separate markings on tube R43C55), in some cases extending for the 9-in. length of the tube segment (See Figures 7.12, 7.13 and 7.14)

- Metallographic examination of axial markings showed surface characteristics similar in appearance to cold working of the metal for depths ranging from 0.0001 to 0.001 in (See Figure 7.15).

- Scanning electron-microscope (SEM) examination of a horizontal (transverse) fracture surface on one of the segments examined showed features similar to fatigue striations. (See Figure 7.16)

- The change in tube thickness along most of the length of the rupture in the segment of tube R42C55 was similar in appearance to a knife edge. (See Figure 7.17)

The Task Force also reviewed the TV-optics video tape that showed the existence of loose tubes, tubes that had ends severed close to the tubesheet, and loose tube fragments in the previously plugged peripheral tube areas. The licensee stated that these loose materials were subjected to an average cross-flow velocity of 15 fps during normal steam generator operation. These foreign objects were removed from the periphery of the tube bundle in the previously plugged tube areas for further examination by the licensee.

Final identification of the failure mechanism and the sequence of events that led to the failure of tube R42C55 will be made by the licensee upon completion of further metallurgical analyses, steam generator fluid dynamic studies, and steam generator mockup tests.

Since the tube rupture event, the NRC has had an effort underway to closely monitor the B steam generator repair and recovery activities at Ginna. Rochester Gas and Electric Corporation has been required to receive the NRC staff's approval prior to their undertaking significant or irreversible modifications or other corrective measures to the steam generator. The NRC staff will review the licensee's submittal on the event prior to granting permission for Ginna's return to power. The staff's review will include evaluations of the cause of the steam generator tube failure, the extent of damage to the B steam generator, repairs and modifications performed, and future action and inspections that the licensee has proposed. Additionally, as reported in SECY-82-72A, a proposed management structure has been developed for an NRC/Industry coordinated program to address steam generator degradation. This program was established to develop any necessary short term fixes and long term research activities that could promote resolution of the steam generator degradation problem.

7.4 Other Equipment Problems During the Event

7.4.1 Pressurizer Power-Operated Relief Valve

The two pressurizer power-operated relief valves (PORV) are Copes-Vulcan, 3-in., Model 1513, valves with Model D-100-160 reverse-acting pneumatic operators. Figure 7.18 shows a cutaway view of a PORV. Both PORVs had been replaced in 1980 during a modification outage to provide positive valve indication in accordance with TMI Action Plan requirements. Prior to this time, the PORVs had been part of the originally installed plant equipment. The licensee stated that valves similar to both PORVs were tested under the program implemented for the licensee by the Electric Power Research Institute (EPRI). This program consisted of full-scale operating tests on prototypical valves and was completed in December 1981. During the course of this test program, a Velan, Model B10-3054B-13MS, block valve was also tested. This Velan valve was of the same model as those installed at Ginna; however, the valve motor operators were slightly different. All test results were judged to be statisfactory by EPRI and the licensee.

In 1979, the reactor coolant system low-temperature overpressure protection system was installed. This system uses the PORVs to prevent overpressurization when the plant is shutdown and at a low temperature with the pressurizer completely filled with water.

During the tube rupture event, operators actuated PORV PCV430 to reduce the pressure differential between the reactor coolant system and the B steam generator. The other PORV (PCV431C) was not operated during the event. Use of PORV PCV430 instead of pressurizer spray was discussed in the licensee's steam generator tube rupture procedure for the purpose of decreasing RCS pressure to limit leakage. Use of the PORV instead of pressurizer spray was made necessary because the reactor coolant pumps which provide normal spray pressure were secured early in the event and because a temperature limit on the use of auxiliary spray was exceeded. PORV PCV430 performed successfully through three complete open-close cycles. After a fourth valve opening, the operators attempted to close the valve, but it partially closed, reopened, and stuck in the full open position. The operator closed pressurizer block valve PCV516 at about 10:11 a.m.

On January 27, while PCV430 was still stuck open, the dc control power fuses for the valve actuator's air supply solenoid were removed; the valve remained open, thus indicating that the problem was mechanical, not electrical. On January 28, PCV430 closed without operator action. PCV430 and its actuator were subsequently disassembled and inspected. No signs of physical damage or wear were noted. On February 3, PCV430 was stroked three times using a local, manual, air-loading signal. The valve started to open with 62-psig air pressure to the diaphragm, and it completed opening at 85-psig air pressure. The valve started to close when the air pressure to the diaphragm dropped to 60 psig and was fully closed at 40 psig. The opening and closing air pressures were found to be repeatable. The valve was then manually cycled six times from the control room. During each cycle, PCV430 operated smoothly in both the open and close directions.

The licensee shifted attention to the pneumatic control systems for PCV430 and PCV431C. As stated earlier, PCV430 and PCV431C are operated through the reactor coolant system low-temperature overpressure protection system. A simplified drawing of this system is shown in Figure 7.19.

Solenoid valves SV8619A and SV8619B are used to select the normal or low pressure protection modes of operation by connecting either instrument air or nitrogen pressure to the PORV actuators. In normal operation, instrument air supplies the pneumatic pressure for manual and automatic valve control. To open PCV430, SV8620A is energized and air flows through SV8620A and SV8619A to the PORV actuator. To close PCV430, SV8620A is deenergized and the actuator line is vented through SV8620A to atmosphere. Control of PCV431C is similar, using instead SV8620B and SV8619B.

In the low-temperature overpressure protection mode, SV8620A and B are deenergized and PORV position is controlled by SV8619A and B. To open PCV430, SV8619A aligns the nitrogen header to the PORV actuator line. To close PCV430, SV8619A aligns the PORV actuator line to the instrument air line and actuator pressure vents through SV8620A. Again, PCV431C is controlled in a similar manner.

Because the closure time for PCV430 and 431C needed to be retarded to allow their use in the overpressure protection mode, the licensee crimped the exhaust lines from SV8620A and SV8620B during installation and testing of the nitrogen system. Subsequent to the event, the licensee determined that the vendor's installation and maintenance instructions for SV8620A and SV8620B specifically prohibited restricting the exhaust line. In addition, these instructions discussed the need for a filtered air supply to these valves.

SV8620A and SV8620B are normally closed, American Switch Company (ASCO) model NP8613A74E, three-way, diaphragm-operated, solenoid, pilot-controlled valves. The vendor has stated that the valves are qualified to standard IEEE-323-1974 requirements for application inside containment.

SV8620A operated successfully during the post-event testing of PCV430. The licensee then disassembled and inspected SV8620A. The valve internals were clean, free of foreign material, and showed no signs of damage. The licensee further determined that the solenoid was in proper working condition.

The licensee performed several bench tests to identify possible failure modes but was initially unable to cause a failure mode for SV8620A which would produce the effects on PCV430 operation noted during the tube rupture event.

On advice from a Westinghouse representative, the crimped exhaust line from SV8620A was replaced with a valved line to provide a variable exhaust restriction. The valve was then bench tested with progressively greater degrees of exhaust flow restriction. Initially, no failures developed. Eventually, after further restriction of the exhaust line, the licensee was able to show that, after several cycles, SV8620A would lock up so that the actuator line remained at a fixed pressure even though the solenoid deenergized. No variations were observed in the actuator pressure during the valve lock-up sequence. The licensee's bench test did not, therefore, demonstrate the pressure changes in the actuator line required to cause the effects observed during the event; i.e., PCV430 starting to close, then reopening. In addition, the exhaust restriction when the valve locked up exceeded that provided by the crimp originally in the exhaust line.

The licensee then installed SV8620A with the valve on its exhaust in the normal PCV430 control system. PCV430 was cycled several times and SV8620A's exhaust port was increasingly restricted. Again, the licensee was able to cause PCV430 to stick open but was unable to get it to partially close, then reopen, before becoming stuck. Also, the exhaust restriction on SV8620A when PCV430 stuck exceeded that provided by the crimp.

At the request and under the supervision of the NRC Task Force, the licensee performed an additional series of bench tests on a spare ASCO valve similar to SV8620A, with a similar variable exhaust restriction. Valve lockup was again demonstrated. This test series demonstrated a failure mode capable of producing the observed effects on PCV430. To understand the failure mode demonstrated during the Task Force's test, a brief description of ASCO valve operation is provided below.

A cutaway view of an ASCO NP8613A74E valve is shown in Figure 7.20. The valve is shown in its deenergized, depressurized condition. If air pressure is supplied to the supply port while the solenoid remains deenergized, the supply-side diaphragm shifts to block air pressure to the actuator port. The solenoid core assembly prevents the supply-side diaphragm actuating pressure from bleeding to the exhaust port. It also acts against the disc assembly spring to keep the disc assembly away from the exhaust pilot port, thereby assuring that the exhaust-side diaphragm does not block the exhaust path.

Energizing the solenoid moves the core up, allowing the disc assembly spring to force the disc up until it covers the exhaust pilot port. This allows supply air to flow past the supply-side diaphragm, through the insert assembly, to the exhaust-side diaphragm, then through a hole in the exhaust-side diaphragm to the actuator port. Internal valve pressure then forces the supply-side diaphragm open, connecting the supply air directly to the actuator port. The exhaust-side diaphragm then seats as actuator port pressure rises, and flow to the exhaust port causes the pressure differential across the exhaust-side diaphragm to reach a critical value. Steady-state conditions are finally established with supply and actuator port pressures equalized, the supply-side diaphragm open, and the exhaust-side diaphragm closed.

Subsequent deenergizing of the solenoid causes the core to drop. The core pushes the disc assembly downward, venting the exhaust-side actuating pressure through the exhaust port. Further, the core then blocks the vent path through the insert assembly for the supply-side diaphragm actuating pressure. The exhaust-side diaphragm is then pushed open by actuator port pressure, and valve internal pressure then starts to drop as both the supply air and the actuator port air both flow through the exhaust port. As the internal pressure continues to decrease, supply air flow increases until the differential pressure across the supply-side diaphragm reaches a critical value, at which time the supply-side diaphragm shifts to its closed position, blocking supply pressure to the actuator port. The actuator port continues to bleed to the exhaust port until it has depressurized.

If the exhaust port is restricted, the flow to the exhaust port results in a back pressure felt in the valve internals. If the restriction is severe, the flow to the exhaust is too low to generate the differential pressure across the supply-side diaphragm required to cause it to close on solenoid deenergization. The valve then locks up, and the pressures of all three ports equalize. Once the three pressures equalize, further solenoid operation will not affect actuator pressure, and the PORV controlled by the ASCO valve will remain in a position dictated by the back pressure alone. The greater the restriction in the exhaust line the higher the back pressure will be and the wider the PORV will be open.

For the NRC Task Force's test, pressure gages were installed on the supply, actuator and exhaust ports. The solenoid was then energized, pressurizing the actuator port and attached piping to the 100 psig supply pressure. The exhaust port variable restriction was then fully shut and the solenoid deenergized. The exhaust-side diaphram was then observed to open rapidly, pressurizing the exhaust port to full supply-side pressure.

Starting with this locked up condition, the degree of restriction was then slowly reduced until the supply-side diaphragm was observed to close. The supply, actuator and exhaust port (back pressure) pressures were observed to track each other closely as the degree of restriction was further reduced and the flow from the air supply was allowed to increase. In the NRC Task Force's test, using a short air supply line, the critical supply flow threshold, necessary to provide the differential pressure for the supply-side diaphragm to close, was not reached until supply pressure had dropped to about 80 psig. Had the supply line been as long as that found in the actual installation within containment, the supply port pressure and therefore the actuator port pressure, would have been significantly lower when the critical supply air flow threshold was reached.

After the threshold restriction for lockup had been demonstrated, the degree of exhaust restriction was then further reduced slightly and the solenoid valve was cycled several times to demonstrate proper operation. In each case, there existed a period, after solenoid deenergization, where there was a high air flow from the actuator and supply ports before the supply-side diaphragm closed.

The final test phase then started with the solenoid energized, the actuator and supply pressure ports connected, and the variable restriction open just enough to allow proper operation. The solenoid was deenergized, and the pressure on the actuator part was observed to decrease. Before the flow through the valve internals could increase to the point where the supply-side diaphragm closed, the restriction was increased slightly, increasing the back pressure, locking up the valve, and causing the actuator pressure to stop decreasing and to rise until it stabilized at a higher pressure controlled by the exhaust restriction.

This test series demonstrated a hypothetical scenario that could duplicate the PORV valve transient experienced during the tube rupture event. The decrease in actuator port pressure after the solenoid was deenergized would cause the PORV to start to close. Air flow from the actuator and air supply lines could then carry foreign material into the restricted exhaust port, causing a further flow restriction and an increased back pressure, thus causing the solenoid valve to lock up. The back pressure would then stablize at a new higher pressure, which would cause the PORV to reopen. The PORV would stay in this open position until the foreign material was dislodged.

No other test sequence to date had been able to duplicate the PORV transient experienced during the event, but examination of the solenoid valve internals disclosed no foreign material. The PORV did reclose by itself two days after the event at a time believed to correspond with the removal of the concrete shield blocks on the pressurizer cubicle, which gave access to the PORV. Whether foreign material, if it existed, was then dislodged by vibration and blown free by the supply air can only be speculated.

The licensee has modified the RCS overpressurization system to control PORV closure times without the use of crimped exhaust lines on SV8620A and SV8620B. The licensee removed the crimped exhaust lines and installed lines free of restrictions. Check valves have been installed in the actuator lines upstream of the PORV pneumatic operator. Two holes have been drilled through the discs on these check valves. The check valve orientation allows full air flow to open the respective PORV. PORV closure times are extended by the air flow restriction caused by the drilled holes. The modification does not involve the installation of additional filters in the ASCO air supply or in the instrument air system.

[redacted]

7.4.2 Letdown System Containment Penetration

Section 3.2.4 of this report described the lifting of the letdown system relief valve that occurred during the event between about 10:11 a.m. and 12:02 p.m. Section 3.3.5 described the system design that permitted this relief lift to occur. Briefly, because of the design of the letdown line existing at the time of the event, the relief valve would be expected to lift anytime an automatic containment isolation occurred, provided the pressurizer water level remained above a low-level setpoint.

The effects described in Chapter 3 of this report were previously identified by the licensee in February 1981 in connection with a review of TMI Action Plan requirements. They were also discussed in NRC inspection report 50-244/81-09 covering May 1981. The inspection report indicated that the as-built design of the letdown line conflicted with the design described in the Ginna Final Safety Analysis Report (FSAR) because the FSAR showed the three letdown orifice isolation valves to be receiving a containment isolation signal. The inspection report also described an engineering work request issued by the licensee to review and evaluate potential modifications to correct the condition, but at the time of the event, no modification had been performed.

Following the event, the licensee approved a modification to provide automatic closure of LCV427 and the letdown orifice isolations on a containment isolation signal. The modification provided additional contacts in the LCV427 closure circuit which are controlled by the containment isolation system. Upon containment isolation, LCV427 will automatically close; LCV200A, 200B, and 202 will close on interlock as before. Although LCV427 will still reopen on loss of instrument air pressure; LCV200A, 200B, and 202 will remain closed until the containment isolation signal to LCV427 has been reset. Therefore, the orifice isolation valves, not LCV427, provide the functional closure for the letdown line inside containment. Because LCV427 is situated inside the containment missile barrier, added protection was provided to ensure successful closure of the orifice isolation valves in the event of pipe-whip damage to LCV427 or its solenoid operator. The modification described above was completed on February 12.

The licensee currently does not plan to request an amendment to Ginna's Technical Specifications to include either LCV427 or the orifice isolation valves in the list of containment isolation valves. Rather, the licensee intends to continue to take credit for the combination of AOV371 and two manual valves located outside containment for containment isolation purposes. The licensee's quality assurance plan does not specifically include the interlock circuitry between LCV427 and LCV200A, 200B, and 202 in its listing of safety-related equipment; no change to this list is presently planned.

7.4.3 Reactor Coolant Pump Seal Return Relief Valve

Section 3.2.2 of this report described the mechanisms that resulted in the lifting of the reactor coolant pump seal return relief valve. Section 3.3.5 described the system design and showed that relief valve lifts would be expected, based on the existing system design. The licensee does not currently plan to modify the CVCS system to prevent future relief valve lifts.

7.4.4 Pressurizer Relief Tank

The pressurizer relief tank filled primarily as a result of the effects of the letdown relief valve lift. The PORV and the reactor coolant pump seal return relief valve lift were minor contributors to the rise in pressurizer relief tank inventory during the event. The rupture disc on the pressurizer relief tank manway burst, and 1,320 gal of water was released to containment sump A. On January 30, the licensee inspected the internals of the tank, found no signs of damage, and replaced the rupture disc.

7.4.5 Containment Sump A Indication

The containment sump A level is monitored by two channels of instrumentation. An International Instrument vertical meter movement provides indication of each channel in the control room.

After the pressurizer relief tank rupture disc burst, sump A filled. Channel 1 indicated a sump level of about 5.3 ft (about 1,900 gal); channel 2 indicated

[redacted]

9.3 ft (about 8,000 gal). The licensee initially reported the sump level to be at about 8,000 gal, based on the channel 2 indication.

The licensee's instrumentation and controls department personnel determined that the output current signals from each channel's transmitter agreed; the voltage signals to each indicator in the control room also agreed. Further, they determined that a static charge on the meter cover was affecting the performance of channel 2. After this charge was removed, channel 2 indicated 5.3 ft, in agreement with channel 1. The actual volume of water in the A sump was determined to be 1,320 gal, based on the volume pumped out of the sump.

The licensee stated that, in the past, similar static charge problems occurred infrequently at Ginna and affected indications of other plant parameters monitored by Westinghouse model 252 vertical milliamp meters. Examples of parameters monitored by this type of meter include pressurizer level, pressurizer pressure, and steam generator level. The licensee currently does not plan to modify the control room meters to prevent the accumulation of static charges on them.

7.4.6 Steam Generator Trend Recorder

At Ginna, a chart recorder is assigned to each steam generator to monitor the positions of the respective steam generator PORV, the four safety valves associated with the respective generator, and the steam supply valve from the steam generator to the turbine-driven auxiliary feedwater pump. Inputs to the recorders come from limit switches mounted on the monitored valves. A separate recorder also monitors main steam line radiation. The three recorders automatically start on high radiation (about 30 mr/hr) in the respective steam line. They also can be initiated manually by the operator. These recorders were installed in 1981 in connection with the TMI Action Plan requirement for noble gas monitoring of plant effluents.

During the event, the three recorders were manually started by an instrument and controls technician. One B steam generator safety valve lifted five times, but the B steam generator trend recorder failed to indicate these safety valve lifts. In addition, neither the A nor B recorder indicated the opening and closing of the respective steam generator PORVs.

The failure of the B recorder impaired the post-event radiological release assessment, because an accurate safety valve lift duration was not available. This lift duration was estimated by the licensee to be 2 min, based on the accompanying loud sounds heard in the control room.

The licensee's investigation determined that the individual pen recorders were operable during the event; however, the A and B PORV indications were electrically blocked. Slide links in the circuit between the limit switches on each PORV and the respective recorder were found to be open. The licensee has not determined the cause for the failure of the B recorder to indicate the B steam generator safety valve lifts but believes the problem is associated with either the alignment or mounting of the limit switch on the specific safety valve. The licensee plans to test all inputs to both valve position trend recorders and to correct any problems identified by the test during the post-event outage.

7.4.7 Control Rod Drive Mechanism Shroud Fan Control

During the event, the operators recognized that the reactor vessel upper head temperature was decreasing at a much slower rate than the temperature of the remainder of the reactor control system. The temperature remained high because of the effects of the existing head metal temperature combined with the low coolant flow rate in the head area during natural circulation. The operators attempted to start a second control rod drive mechanism shroud (CRDMS) fan to assist in cooldown of the head because this action was described in another Ginna procedure associated with plant shutdown on natural circulation during a station blackout. They were initially unsuccessful in their attempt.

Figure 7.21 is a partial schematic of the CRDMS fan motor controller. Each fan has a similar controller; the components shown in brackets (see Figure 7.21) are those found in the controller of the opposite fan. In the X-coil circuit for each fan is an auxiliary b contact from the breaker for the opposite fan

(52/CRSF-1B or 52/CRSF-1A). The b contact is open if the opposite fan is running. Therefore, the circuit logic prohibits starting a second fan while the first is running. To run both fans, the operator must secure the running fan, then start both simultaneously. Neither the steam generator tube rupture procedure nor the plant shutdown procedure discussed above specifically described the required method for starting the second fan.

Currently, the licensee does not plan to modify the CRDMS fan controllers. The Ginna site staff has requested their corporate engineering department to determine the technical basis for the present interlock and to review the present design.

7.5 Revisions to the Steam Generator Tube Rupture Procedure

The licensee plans to revise Procedure E-1.4 in basically two increments: short-term revisions and long-term revisions. In the short term, the licensee will clarify the procedure based on information gained during the event. In the long term, the licensee, in concert with the Westinghouse Owners' Group, intends to develop optimum recovery guidelines for tube rupture events. Potential areas for further revision include: the reactor coolant pump trip and restart criteria, and the addition of guidance regarding reactor vessel upper head voiding, operation with a full pressurizer, long-term plant cooldown, and steam generator overfill.

The licensee has implemented Revision 11 to E-1.4, since the event. The most significant changes made to the procedure by this revision are:

- the addition of steam generator level deviation and steam-flow/feed-flow mismatch alarms to the faulted generator identification criteria

- the addition of specific guidance on safety injection reset

- the addition of an explanatory note which allows safety injection termination with suspected reactor upper head voiding if natural circulation has been verified

- the addition of a note allowing reactor coolant pump restart with a full pressurizer if cold-leg temperatures are >330°F

The revision did not include specific guidance regarding the method for cooling the faulted steam generator. Also, the reactor coolant pump trip and restart criteria have not been revised beyond the fact that guidance allowing reactor coolant pump restart with a full pressurizer has been added.

7.6 References

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Institute of Electrical Engineering and Electronics Standard IEEE-323-1974.

NUREG-0651, "Evaluation of Steam Generator Tube Rupture Events," L. B. Marsh, March 1980.

NUREG/CR-0718, "Steam Generator Tube Integrity Program - Phase I Report," J. N. Alzheimer, R. A. Clark, C. A. Morris, and M. Vagins, Battelle Pacific Northwest Laboratory, September 1979.

Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Rev. 1, July 1975.

SECY-82-72A, "Coordinated Program for Steam Generators," March 25, 1982.

Westinghouse Electric Corporation, "Design Verification Report for Orifice Ring Replacement, Feedwater Ring Modification, Downcomer Resistance Plate Removal, Tube Lane Blocking, and Redirection of Blowdown Suction," Report EDR 1062. April 21, 1975.

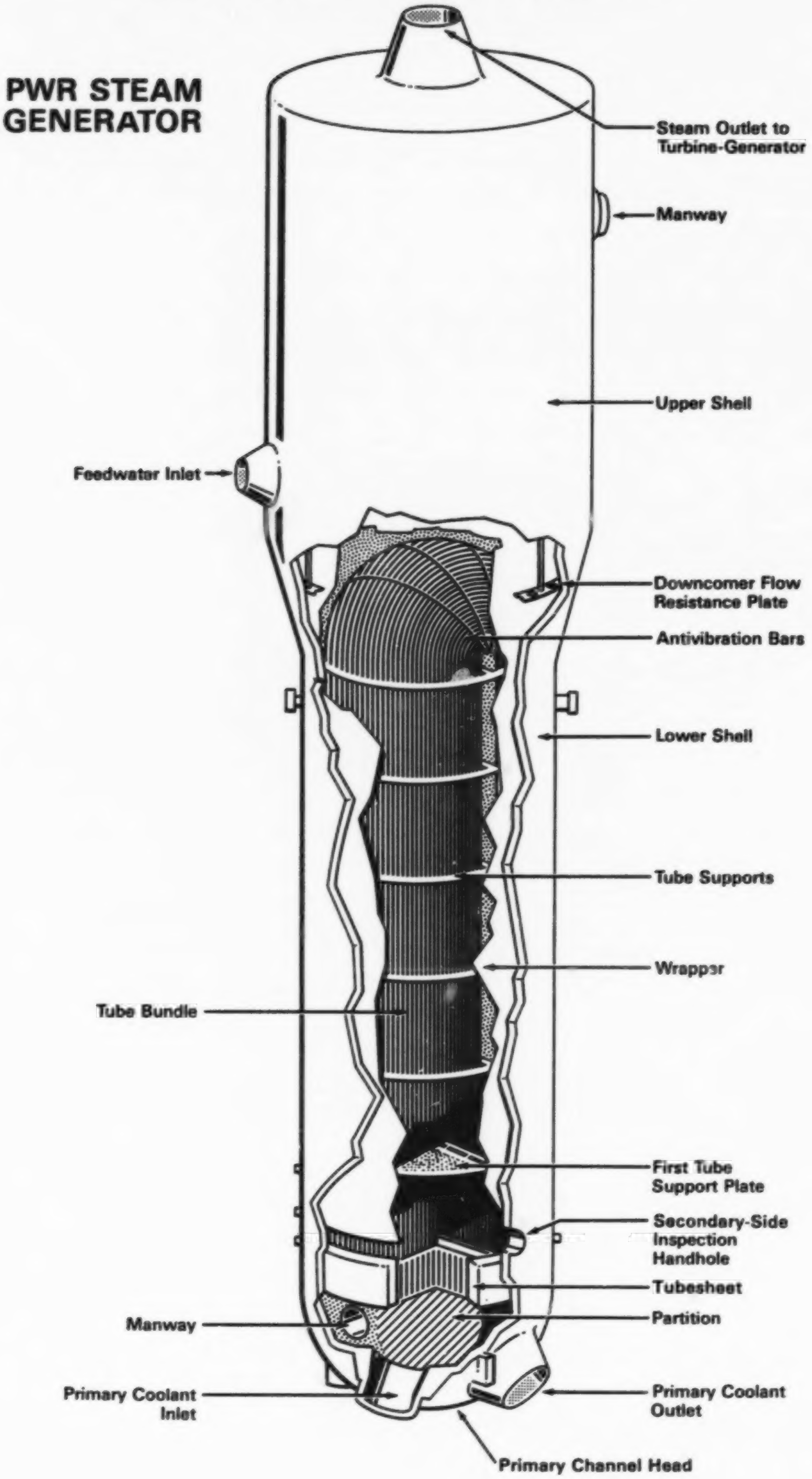

PWR STEAM GENERATOR
Steam Outlet to Turbine-Generator
Manway
Upper Shell
Feedwater Inlet
Downcomer Flow Resistance Plate
Antivibration Bars
Lower Shell
Tube Supports
Wrapper
Tube Bundle
First Tube Support Plate
Secondary-Side Inspection Handhole
Tubesheet
Manway
Partition
Primary Coolant Inlet
Primary Coolant Outlet
Primary Channel Head

Figure 7.1 Westinghouse Model 44 steam generator

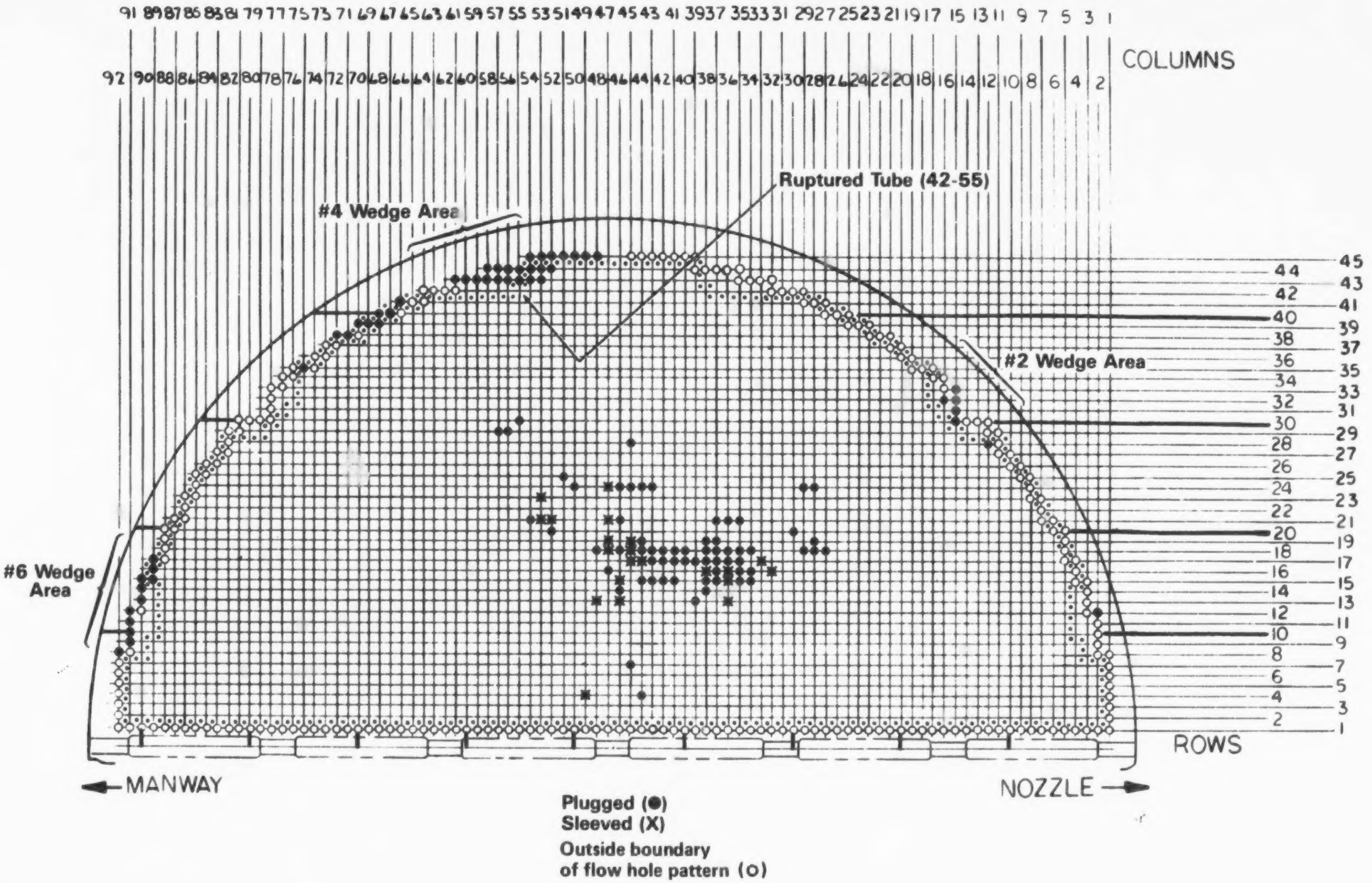
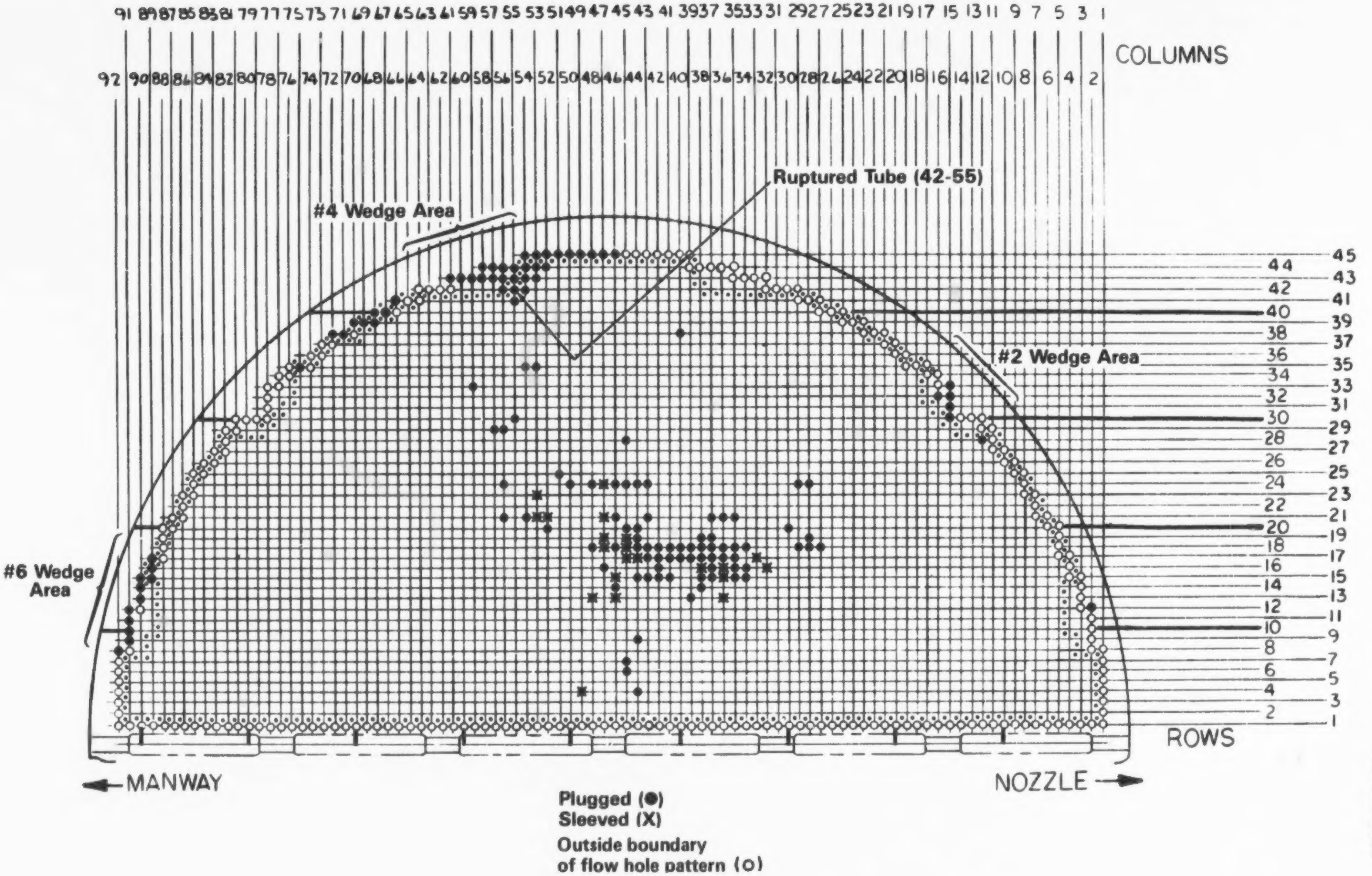

91 89 87 85 83 81 79 77 75 73 71 69 67 65 63 61 59 57 55 53 51 49 47 45 43 41 39 37 35 33 31 29 27 25 23 21 19 17 15 13 11 9 7 5 3 1
92 90 88 86 84 82 80 78 76 74 72 70 68 66 64 62 60 58 56 54 52 50 48 46 44 42 40 38 36 34 32 30 28 26 24 22 20 18 16 14 12 10 8 6 4 2
COLUMNS
Ruptured Tube (42-55)
#4 Wedge Area
#2 Wedge Area
#6 Wedge Area
45 43 41 39 37 35 33 31 29 27 25 23 21 19 17 15 13 11 9 7 5 3 1
44 42 40 38 36 34 32 30 28 26 24 22 20 18 16 14 12 10 8 6 4 2
ROWS
MANWAY
NOZZLE
Plugged (●)
Sleeved (X)
Outside boundary
of flow hole pattern (○)

Figure 7.2 Ginna B steam generator hot-leg tube sheet map before event of January 25, 1982



91 89 87 85 83 81 79 77 75 73 71 69 67 65 63 61 59 57 55 53 51 49 47 45 43 41 39 37 35 33 31 29 27 25 23 21 19 17 15 13 11 9 7 5 3 1
COLUMNS
92 90 88 86 84 82 80 78 76 74 72 70 68 66 64 62 60 58 56 54 52 50 48 46 44 42 40 38 36 34 32 30 28 26 24 22 20 18 16 14 12 10 8 6 4 2
Ruptured Tube (42-55)
#4 Wedge Area
#2 Wedge Area
#6 Wedge Area
44 42 40 38 36 34 32 30 28 26 24 22 20 18 16 14 12 10 8 6 4 2
45 43 41 39 37 35 33 31 29 27 25 23 21 19 17 15 13 11 9 7 5 3 1
ROWS
MANWAY
NOZZLE
Plugged (●)
Sleeved (X)
Outside boundary
of flow hole pattern (o)

Figure 7.3 Ginna B steam generator hot-leg tube sheet map as of February 9, 1982

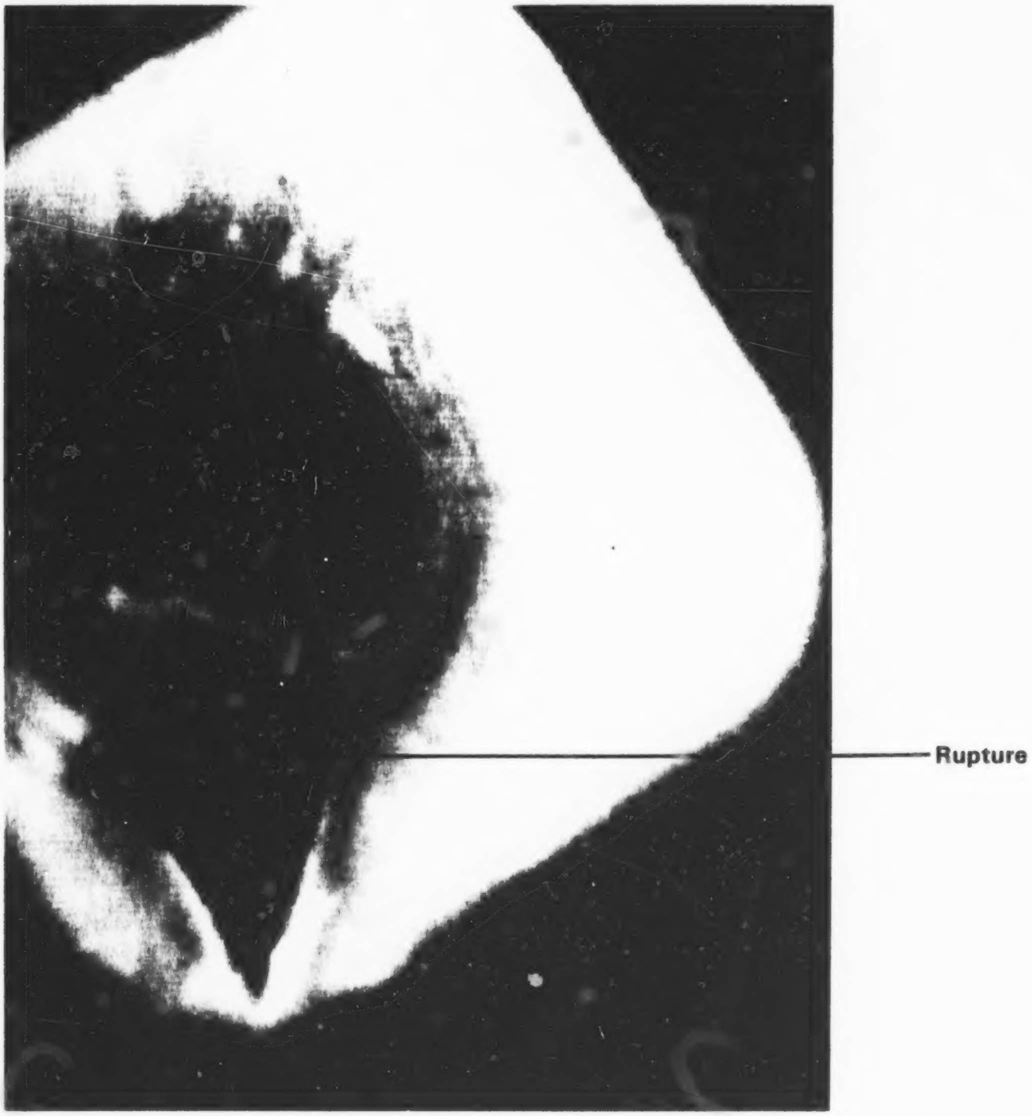
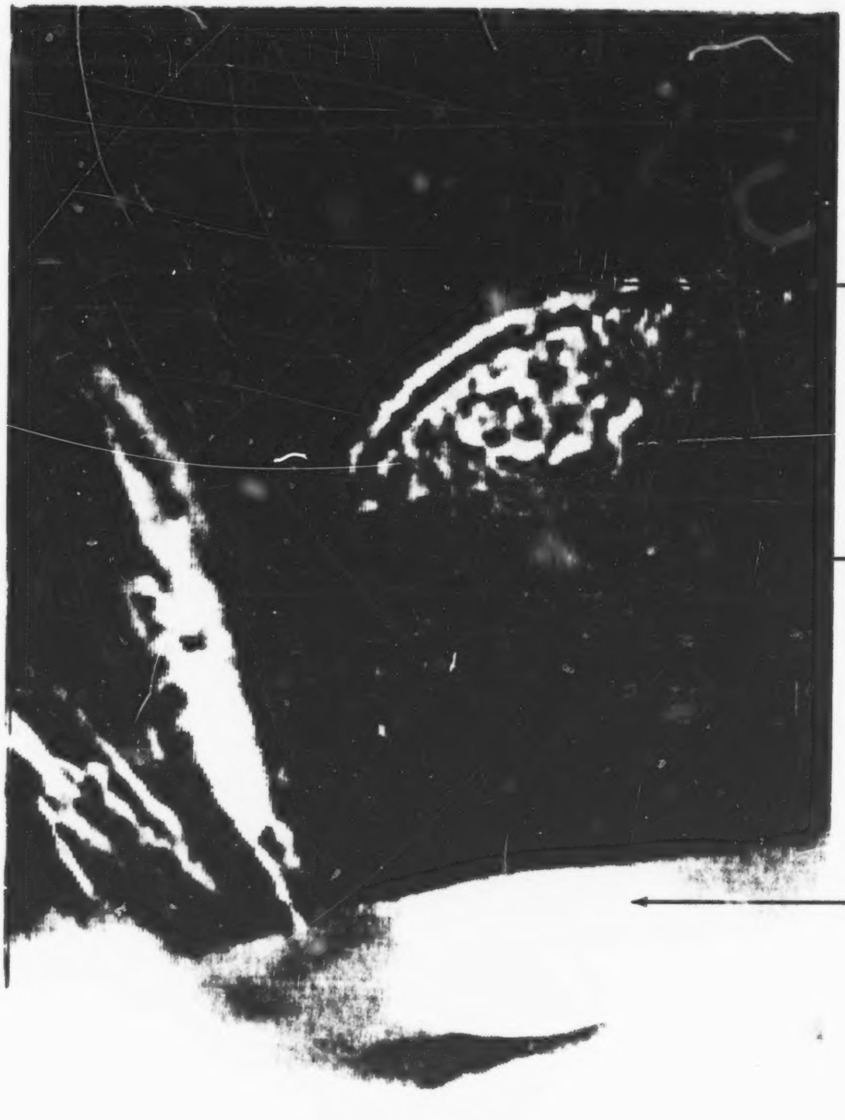


Figure 7.4 Foreshortened fiber-optics view of inner surface of tube R42C55 at rupture location from video-tape recording



Remains of Welded Stiffener Pipe on Stub Barrel
Loose, Longitudinally Fractured Tube
Tubular Lighting System

Figure 7.5 TV-optics computer-enhanced view of loose, mangled tube between tube bundle and stub barrel at R45C53 location; longitudinally fractured and deformed. View looking from bundle toward stub barrel post-weld heat treatment stiffener pipe (from initial fabrication) at upper right.

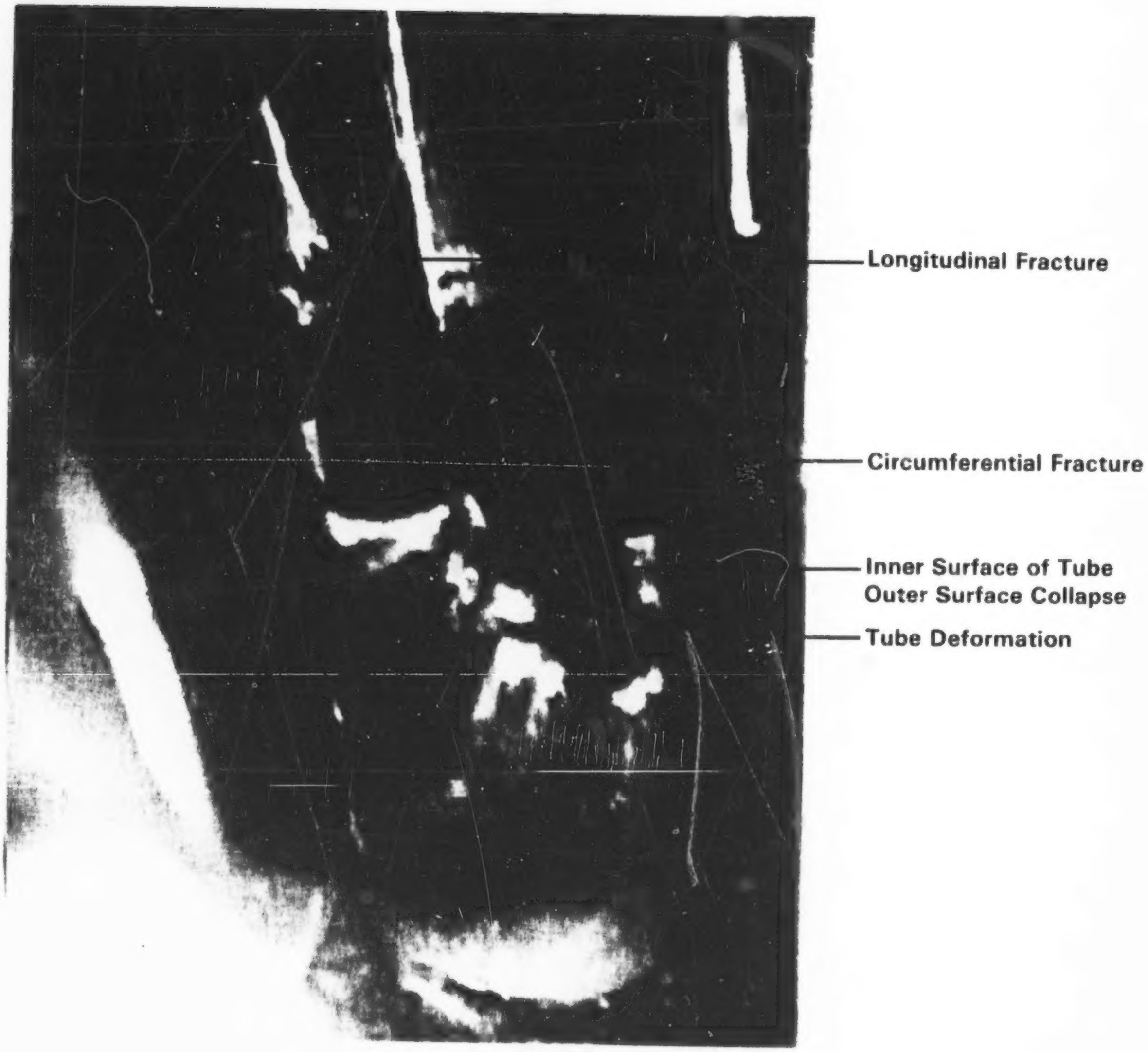
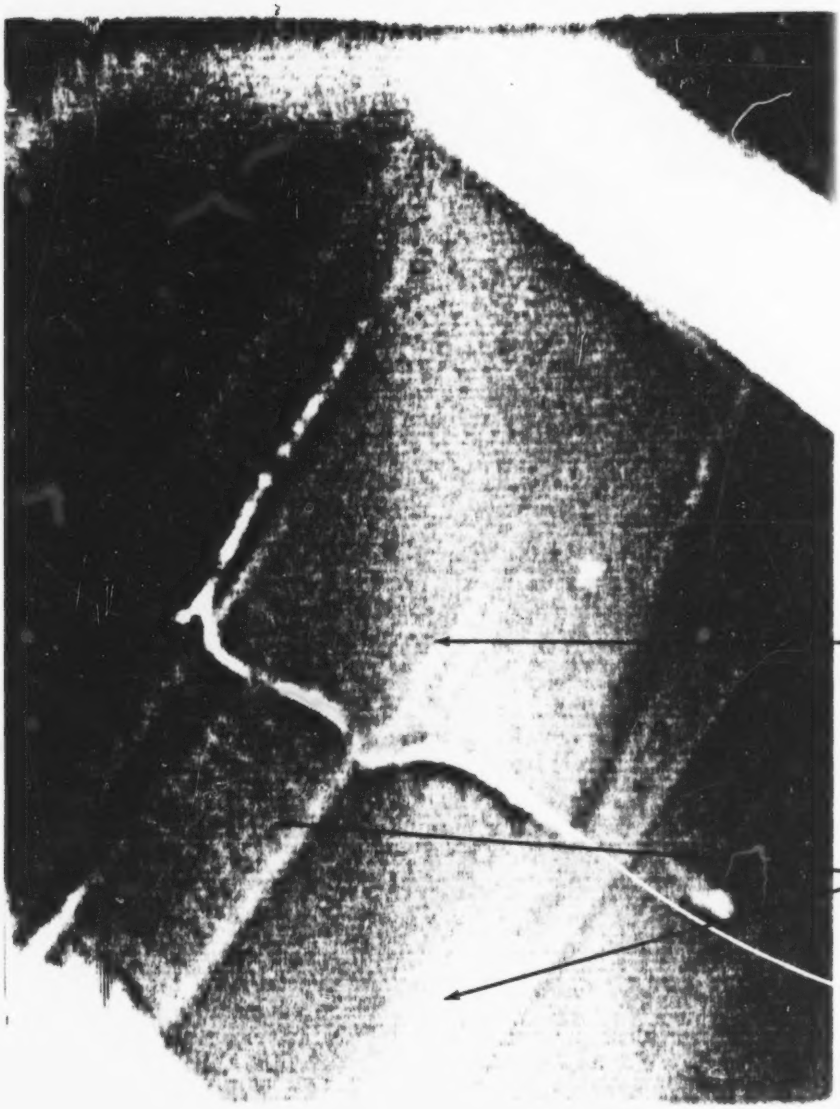

Longitudinal Fracture
Circumferential Fracture
Inner Surface of Tube
Outer Surface Collapse
Tube Deformation

Figure 7.6 TV-optics computer-enhanced view of tube with longitudinal and circumferential fractures and deformation on outer surface at R45C54 location.



Loose Tube Segment with Longitudinal Fracture Deformed To Fit Tube Pattern Contour

Two Tubes in Tube Bundle

Figure 7.7 TV-optics computer-enhanced view of tube segment with longitudinal fracture deformed to contour of tube bundle at R45C54 tube location.

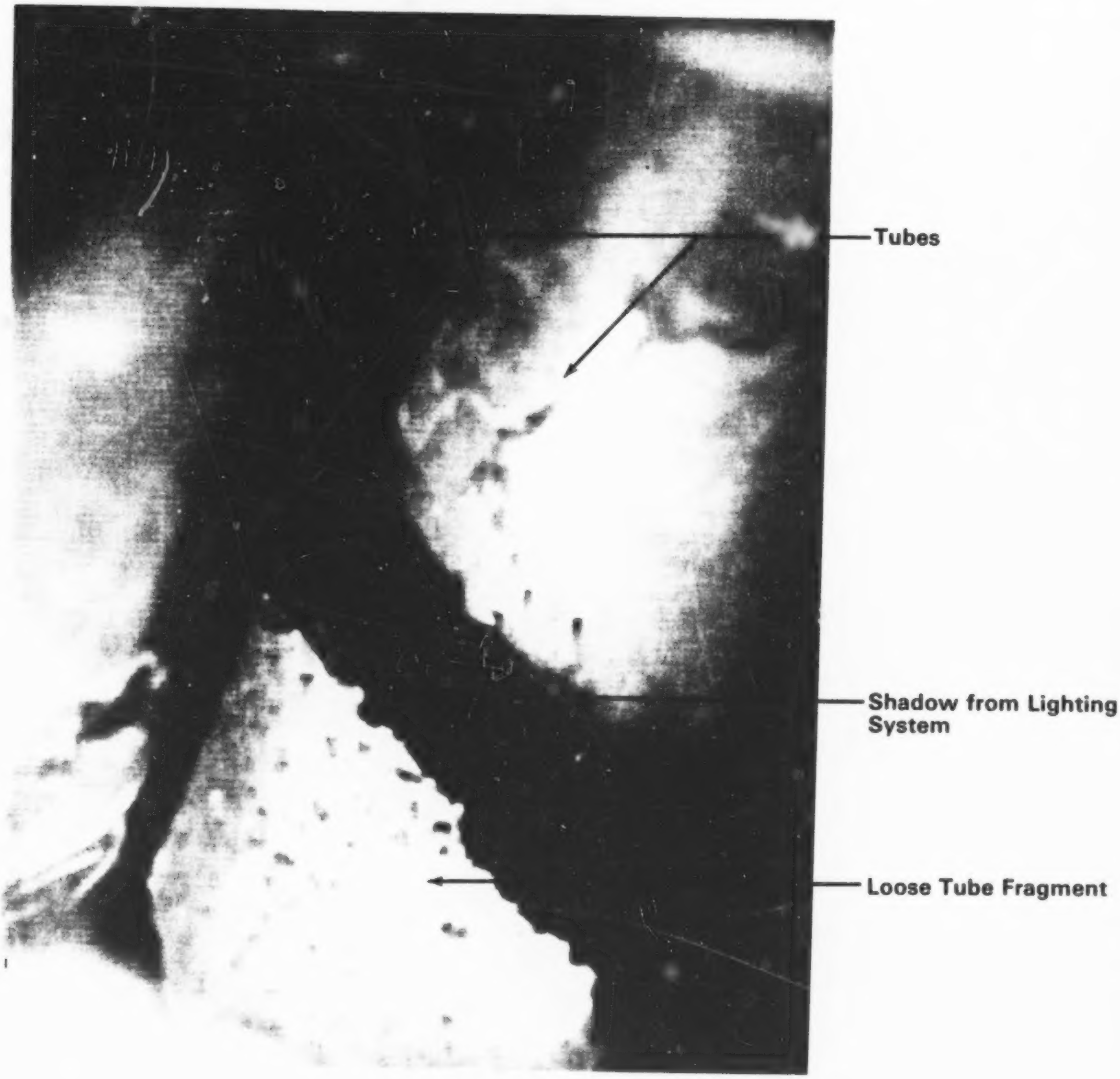
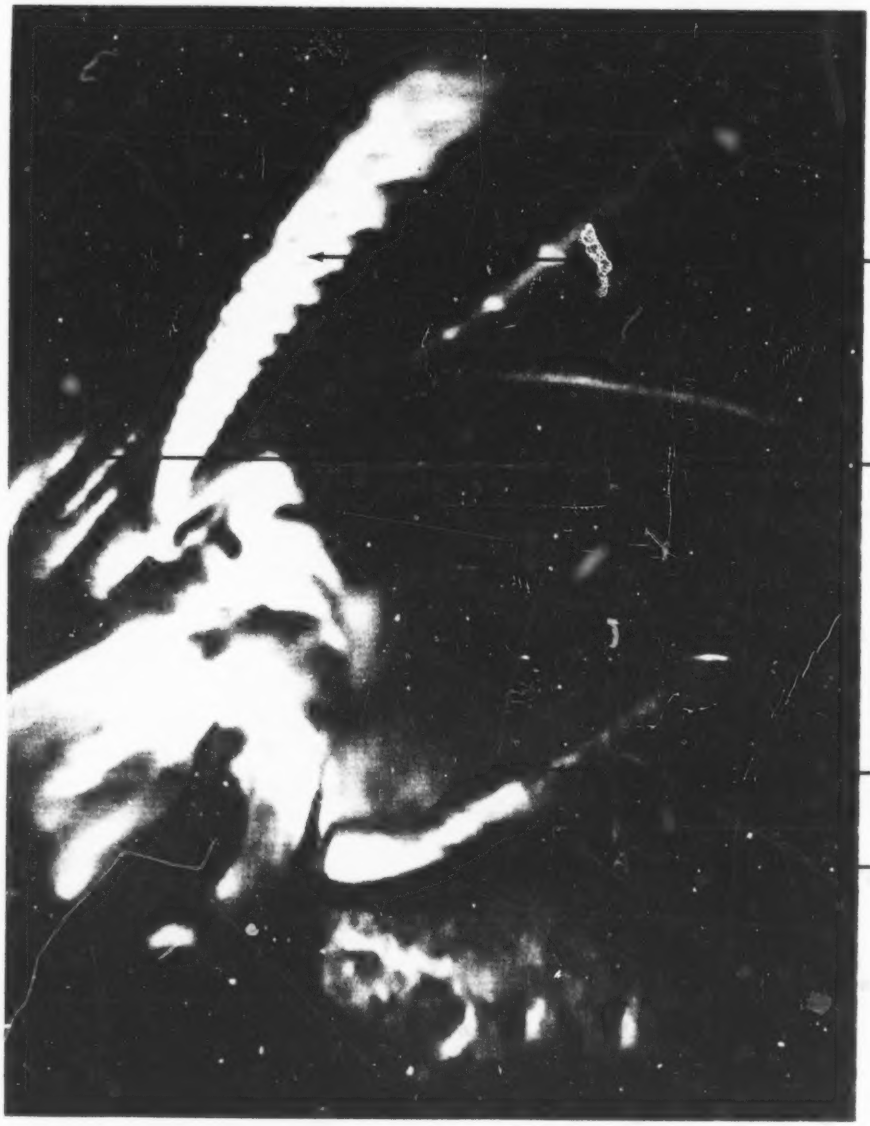

Tubes
Shadow from Lighting System
Loose Tube Fragment

Figure 7.8 TV-optics computer-enhanced view of fractured tube fragment between two tubes at R32C15 location



Rope Used To Pull TV Camera
Tubes in Tube Bundle
Severed Loose Tube
Stub Barrel

Figure 7.9 TV-optics video-tape view of loose severed tube between tube bundle and inside surface of stub barrel at R45C43 location.

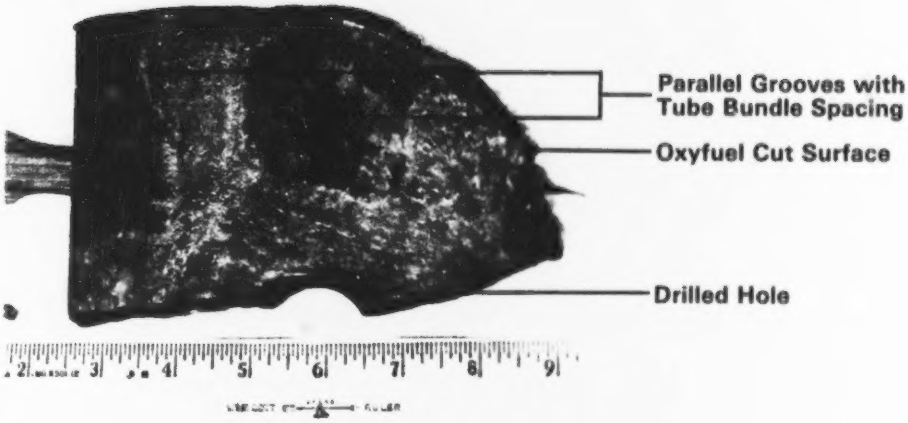

Parallel Grooves with Tube Bundle Spacing
Oxyfuel Cut Surface
Drilled Hole
2
3
4
5
6
7
8
9

Figure 7.10 Large foreign object removed from hot leg of B steam generator (½ in. thick)

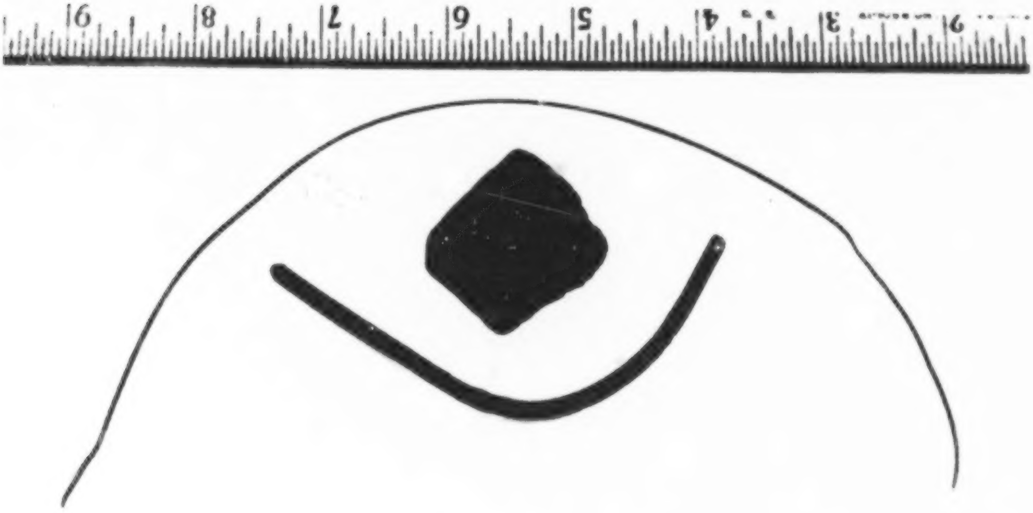


Figure 7.11 Foreign objects removed from A steam generator

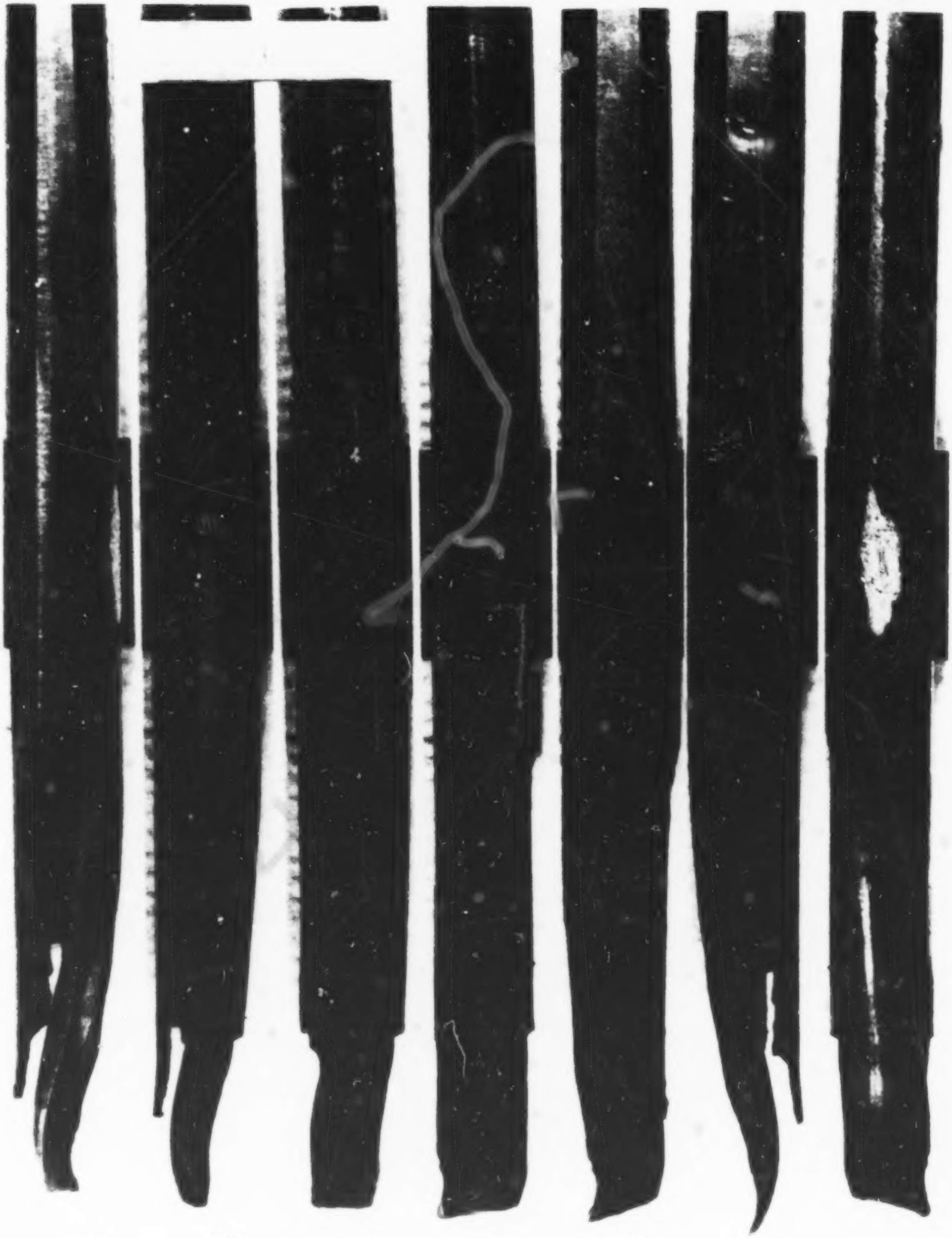

315°
270°
225°
180°
135°
90°

Figure 7.12 Radial views of tube R44C55 showing first 9 in. above tubesheet. Tube detached from remainder of tube in tubesheet. White dot points outward.

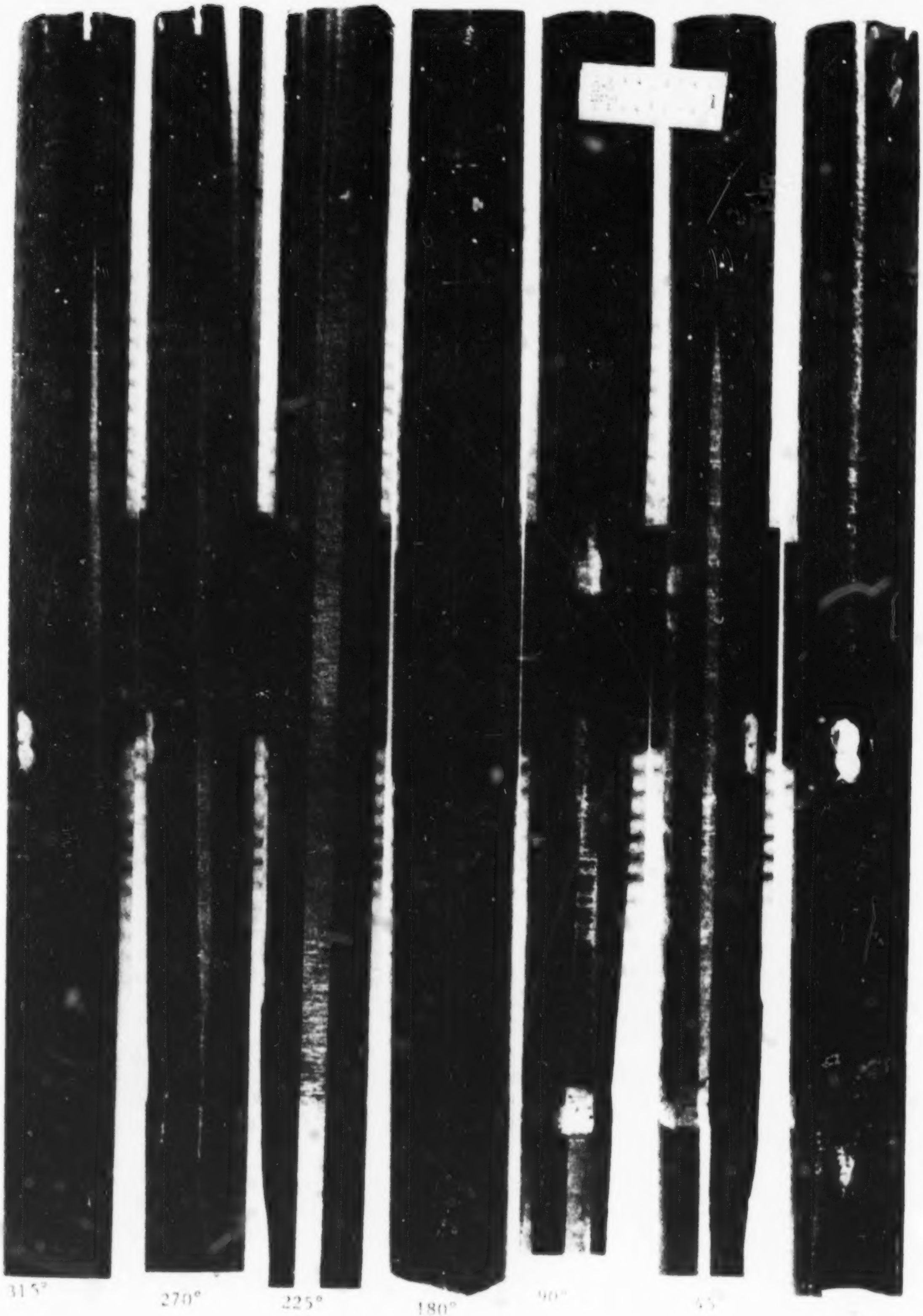

315°
270°
225°
180°
90°
45°

Figure 7.13 Radial views of tube R43C55 showing first 9 in. above tubesheet. White dot points outward.

1
2
270°
180°
90°

Figure 7.14 Radial views of tube R42C55 showing first 9 in. above tubesheet. Rupture features and ballooning deformation prior to rupture are illustrated.

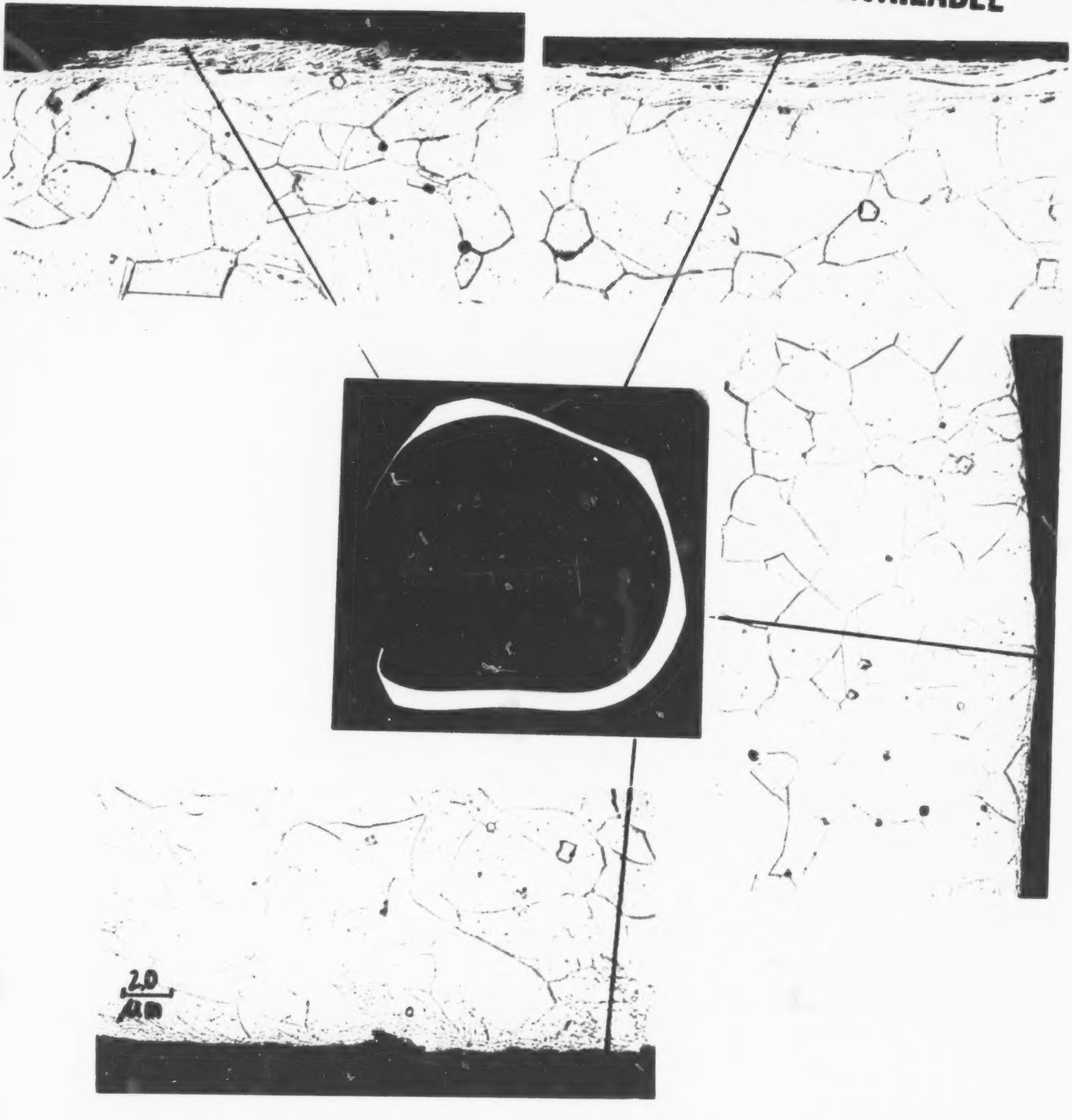


Figure 7.15 Metallographic transverse section of plugged tube R44C55 showing apparent cold work on two fretting wear areas and absence of cold work at virgin metal areas.

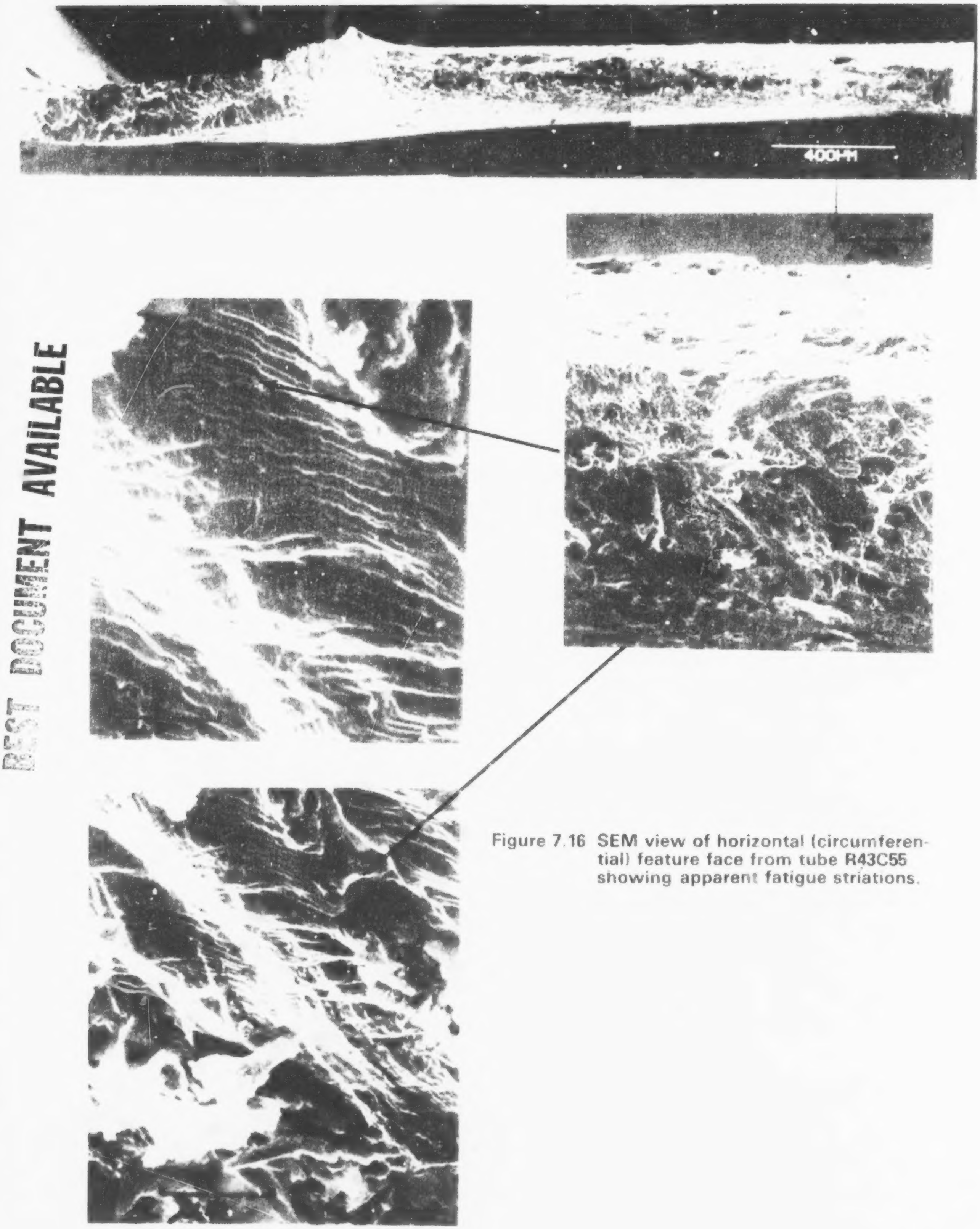


Figure 7.16 SEM view of horizontal (circumferential) feature face from tube R43C55 showing apparent fatigue striations.

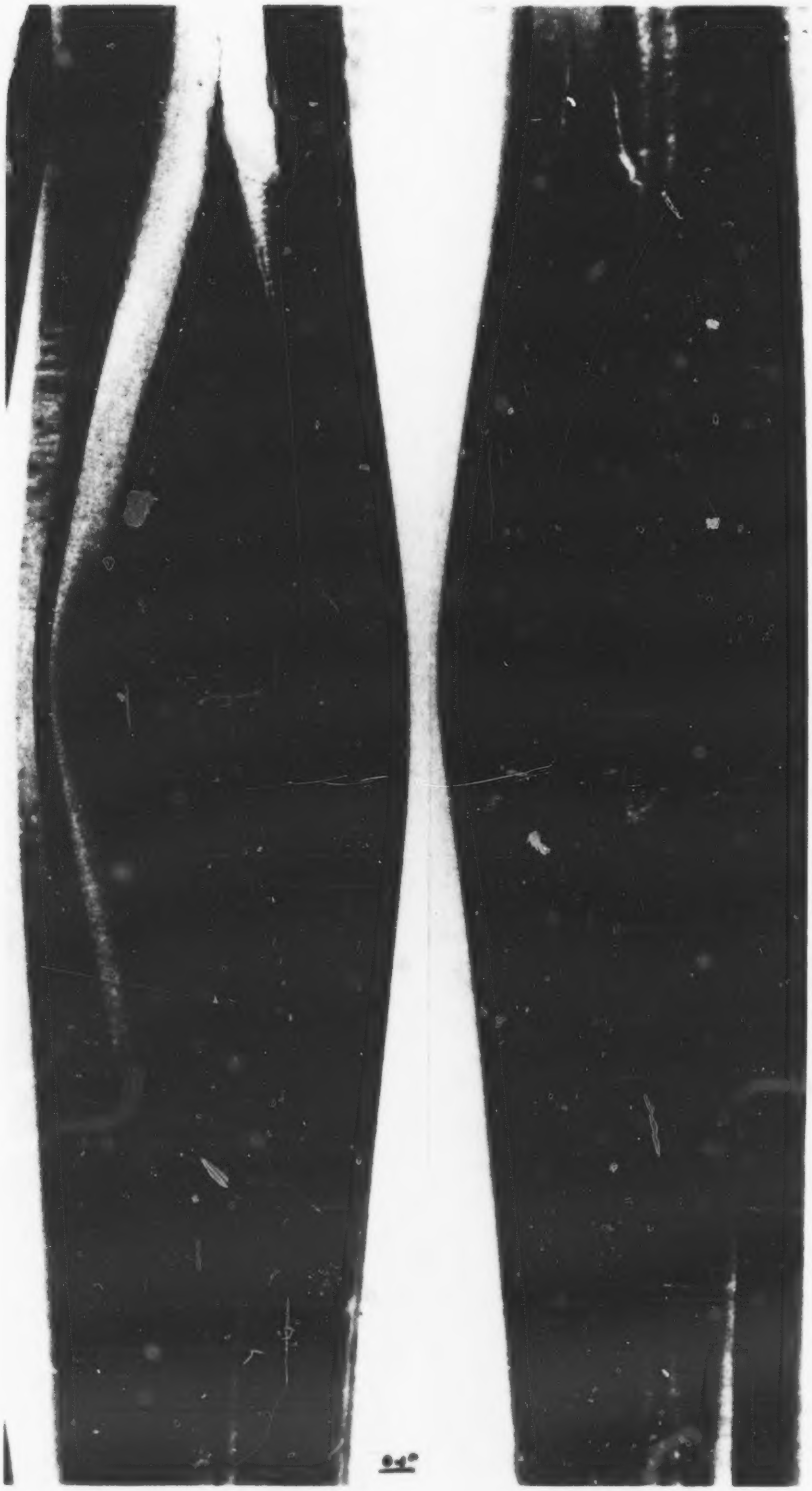


Figure 7.17 Closeup view of rupture in tube R42C55 showing "knife edge" rupture face. 0° orientation points radially outward from tube bundle.

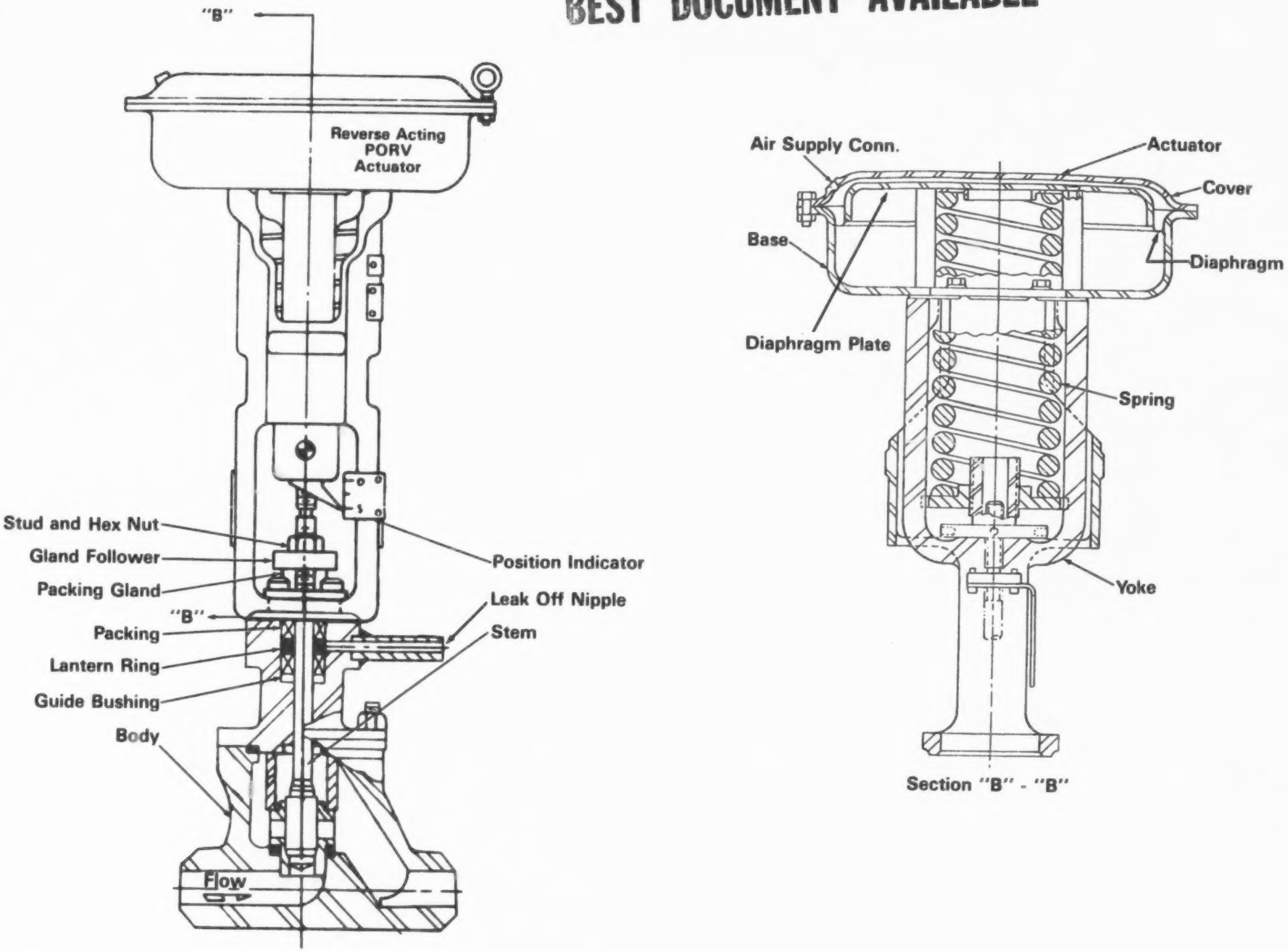

"B"
Reverse Acting PORV Actuator
Stud and Hex Nut
Gland Follower
Packing Gland
"B"
Packing
Lantern Ring
Guide Bushing
Body
Position Indicator
Leak Off Nipple
Stem
Flow
Air Supply Conn.
Actuator
Cover
Base
Diaphragm
Diaphragm Plate
Spring
Yoke
Section "B" - "B"

Figure 7.18 Pressurizer PORV

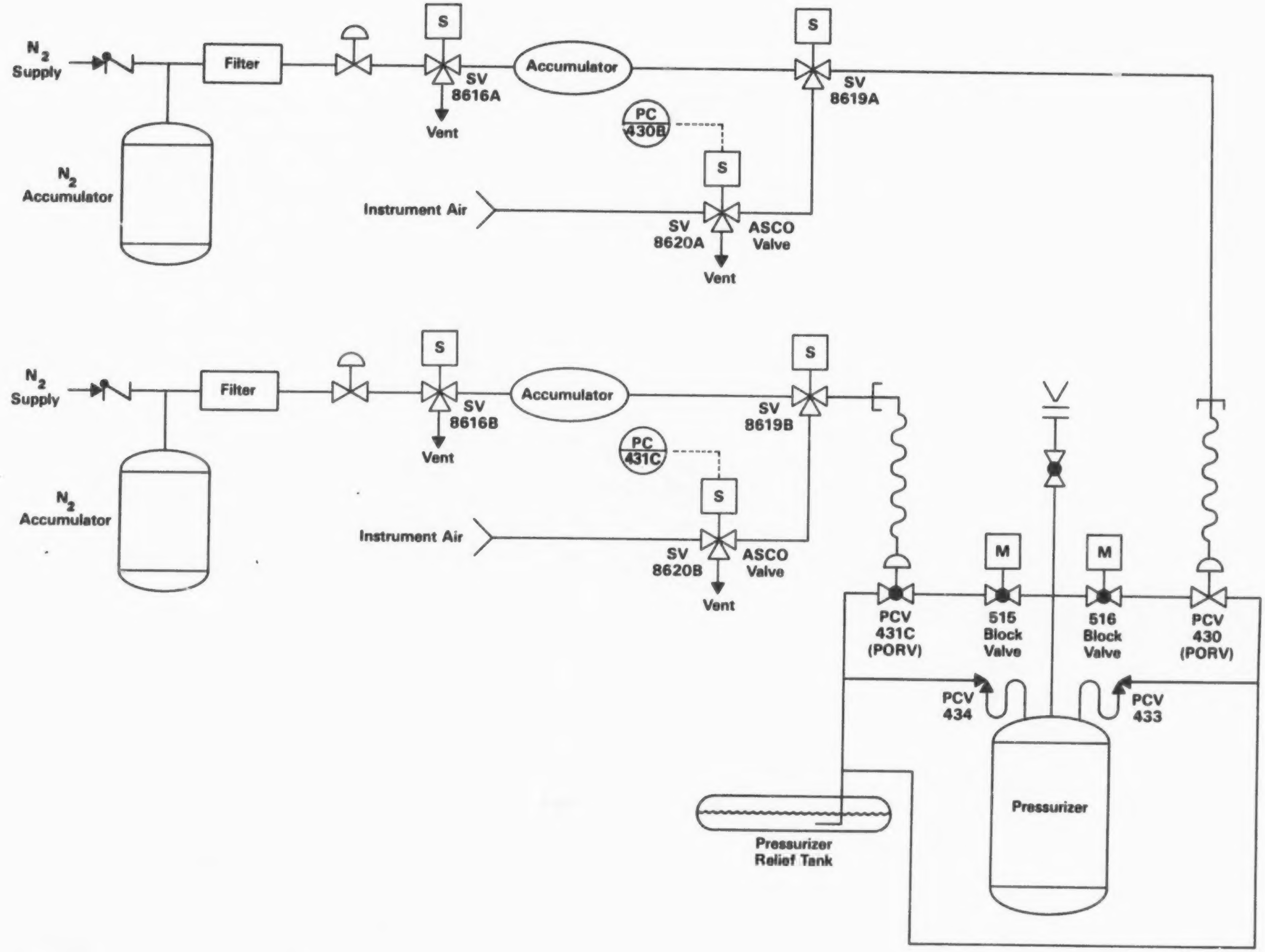
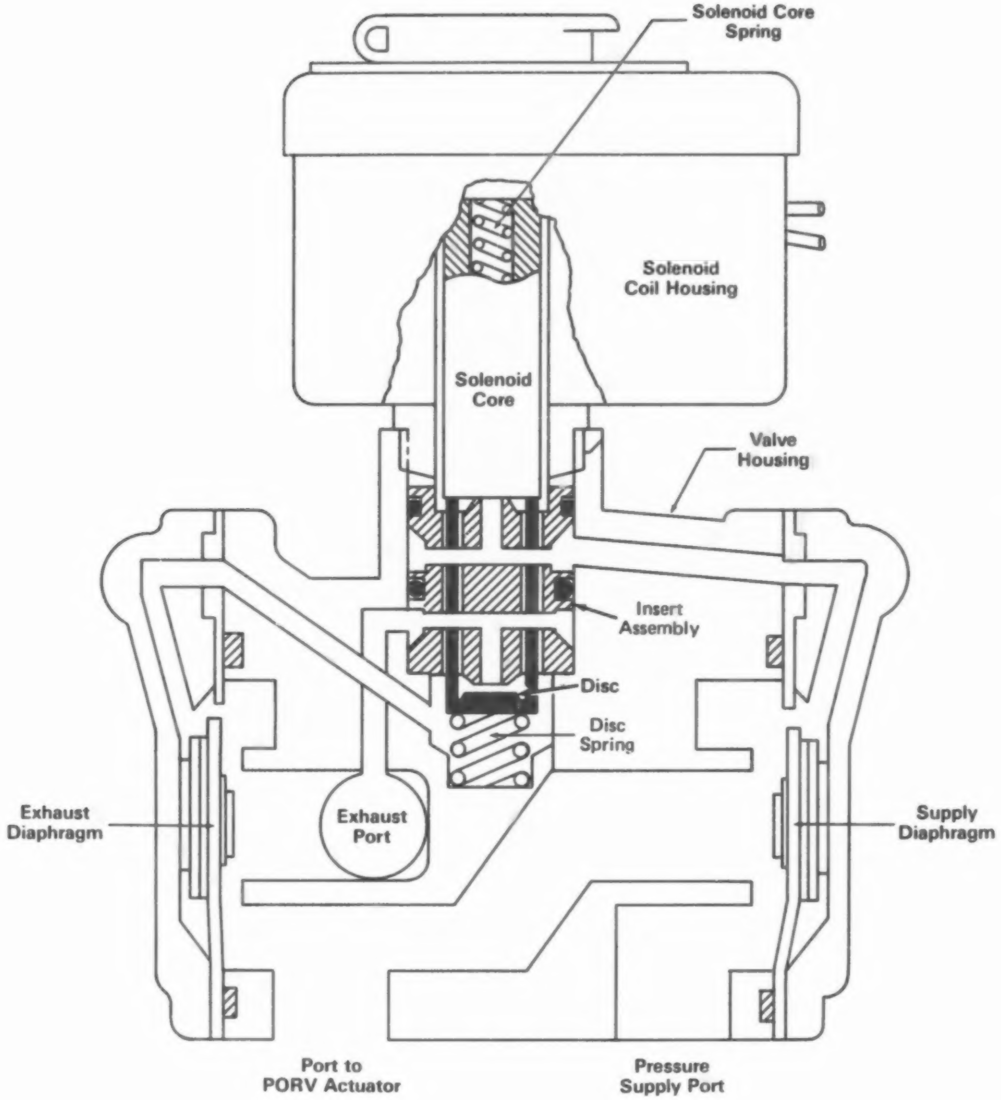
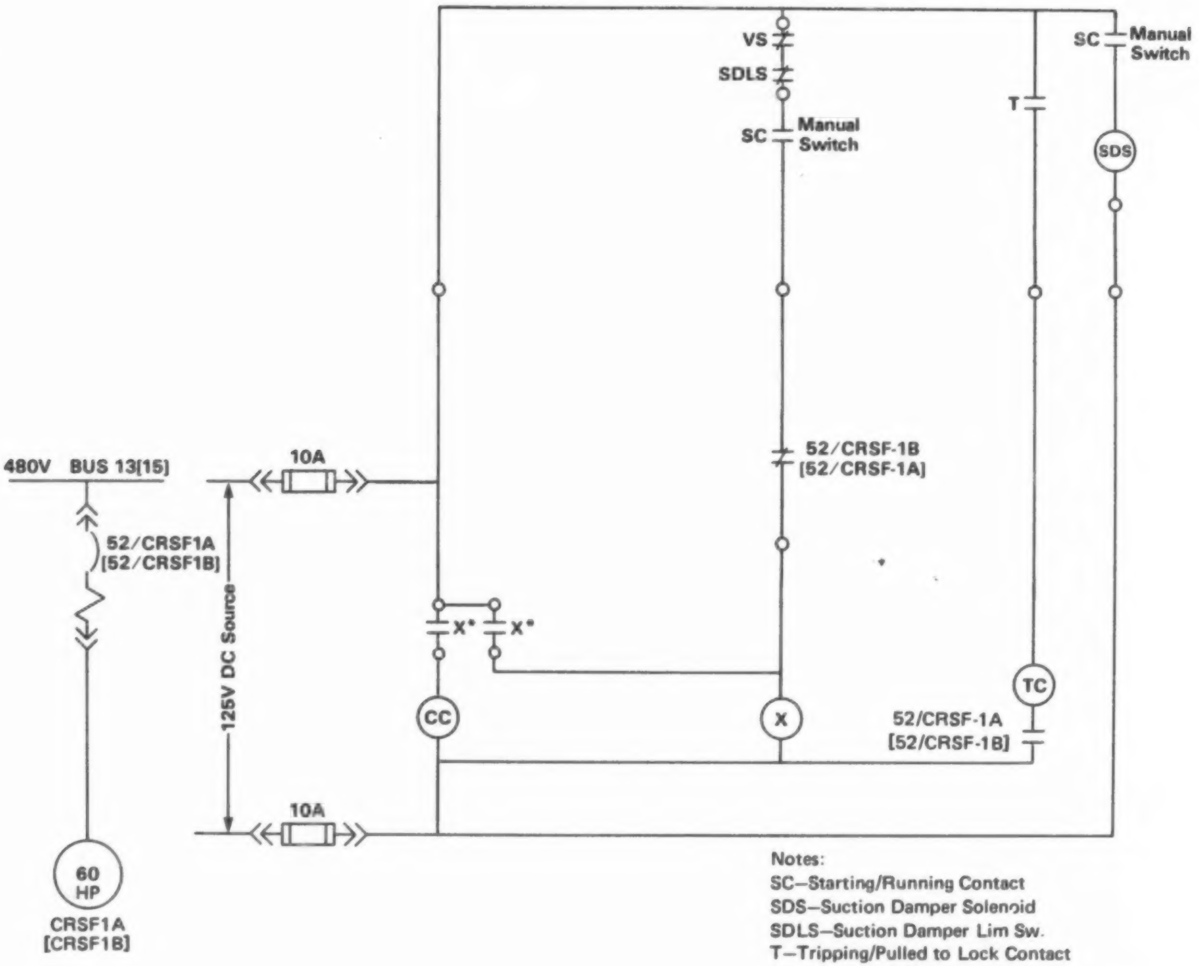

N_2 Supply
Filter
S
SV 8616A
Vent
Accumulator
S
SV 8619A
PC 430B
S
N_2 Accumulator
Instrument Air
SV 8620A
ASCO Valve
Vent
N_2 Supply
Filter
S
SV 8616B
Vent
Accumulator
S
SV 8619B
PC 431C
S
N_2 Accumulator
Instrument Air
SV 8620B
ASCO Valve
Vent
M
M
PCV 431C (PORV)
515 Block Valve
516 Block Valve
PCV 430 (PORV)
PCV 434
PCV 433
Pressurizer
Pressurizer Relief Tank

Figure 7.19 Simplified reactor coolant system overpressure protection system


Solenoid Core Spring
Solenoid Coil Housing
Solenoid Core
Valve Housing
Insert Assembly
Disc
Disc Spring
Exhaust Diaphragm
Exhaust Port
Supply Diaphragm
Port to PORV Actuator
Pressure Supply Port

NOTE:
(Shown without air pressure or electricity)

Figure 7.20 ASCO three-way diaphram solenoid valve


VS
SDLS
SC
Manual Switch
T
SC
Manual Switch
SDS
480V BUS 13[15]
10A
52/CRSF1A
[52/CRSF1B]
52/CRSF-1B
[52/CRSF-1A]
125V DC Source
X*
X*
CC
X
TC
52/CRSF-1A
[52/CRSF-1B]
10A
60
HP
CRSF1A
[CRSF1B]

Notes:
SC–Starting/Running Contact
SDS–Suction Damper Solenoid
SDLS–Suction Damper Lim Sw.
T–Tripping/Pulled to Lock Contact
VS–Vibra Switch Control Contact
Shown Reset
*Contacts Forced Ope
Mechanically on 52/CRSF1A
[52/CRSF1B] Breaker Closure

Figure 7.21 Simplified control rod drive fan motor controller

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This NRC Task Force report documents the circumstances surrounding the January 25, 1982, steam generator tube rupture event at the R. E. Ginna Nuclear Power Plant. It focuses on the period from 9:25 a.m. on January 25, when the tube rupture occurred, to 10:45 a.m. on January 25, when the plant entered the recovery phase. Information outside this period is recounted as necessary to place the event in perspective. The report is intended to describe factual information and significant findings associated with the event and, thereby, provide the required data base for appropriate detailed analysis and recommendations by various NRC offices.

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